Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

May 4, 2011

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy (Vancouver Island) Inc.) ("FEVI")

2012 and 2013 Revenue Requirements and Natural Gas Rates Application

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Attached please find the FortisBC Energy Utilities' ("FEU" or the "Companies") 2012 and 2013 Revenue Requirements and Rates Application (the "Application" or "RRA").

Summary of Requests

This Application follows two-year Negotiated Settlement Agreements for 2010 and 2011 for FEI and FEVI, a two-year revenue requirements decision for FEW for 2010 and 2011, and a single year revenue requirements decision for Fort Nelson for 2011. In this Application, each of the FEU is requesting rate approvals for 2012 and 2013. In particular:

- FEI is seeking approval of an increase in its rates for delivery service for a two-year period commencing January 1, 2012. The increase sought for 2012 is 5.0%, with an additional effective base rate delivery increase of 6.4% in 2013. These proposed increases result in modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.4% or $24 in 2012 and an additional 3.0% or $31 in 2011.[1]

- FEW is seeking an increase in its rates for delivery service of 2.2 per cent in 2012, with an additional increase of 11.9 per cent (cumulative increase of 14.1 per cent) in 2013. This, results in an increase to the annual bill of an average Whistler residential

[1] Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on the current commodity and midstream charges effective April 1, 2011 and excludes the impacts of rate riders.

customer of 1.5 per cent or $22 in 2012 and an additional 7.1 per cent or $115 in 2013.[2]

- Fort Nelson is seeking an increase in its rates for delivery service of 6.5 per cent in 2012, with an additional increase of 1.6 per cent (cumulative increase of 8.1 per cent) in 2013. This, results in an increase to the annual bill of an average Fort Nelson residential customer of 2.3 per cent or $26 in 2012 and an additional 0.6 per cent or $7 in 2013.[3]

- FEVI is seeking to maintain current rates for all customers except those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012. FEVI proposes to utilize part of the surplus that will exist in the Rate Stabilization Deferral Account ("RSDA") to allow for rates to remain at 2011 levels through to the end of 2013. The RSDA was approved as part of the last FEVI revenue requirements application, with the intention of using the accumulated balance to manage cost pressures unique to FEVI. The rate proposal in the present Application implements the previously developed strategy.

- FEI, FEW and Fort Nelson are also seeking approval of the Rate Stabilization Adjustment Mechanism ("RSAM") rider for 2012.

In the Fall of 2012, the Companies intend to seek the necessary approvals to amalgamate effective January 1, 2013 and to introduce harmonized rate structures effective on the same date. As the anticipated effective date of amalgamation and harmonized rates falls within this two year revenue requirements period, the orders sought in respect of 2013 rates for the individual entities have been expressed as being conditional upon amalgamation and harmonized rates not taking effect. And, in anticipation of the upcoming application to amalgamate and introduce harmonized rates, the FEU are collectively applying in the present Revenue Requirements Application for approval of the combined utility cost of service for 2013. The FEU believe, for the reasons described in Section 1.2.5 of the Application, that this is the most efficient way to proceed. In order to avoid any concern about predetermining in this Application the substantive merits of the Fall application to amalgamate and implement harmonized rates, this requested approval has been phrased to make it clear that the determination of the amalgamated cost of service in this Application is conditional upon future Commission orders and in no way speaks to the merits of amalgamation and harmonized rates. The FEU thus believe that all inquiries regarding amalgamation and harmonized rates should also be deferred to the Fall 2012 application.

Proposed Process

In terms of process, the FEU are open to a negotiated settlement of all of the issues, should the parties believe that is a possibility. Otherwise, the FEU believe that this Application can be addressed efficiently and effectively through a written hearing process. The proposed regulatory timetable, and a discussion of issues that the FEU intend to address at the

[2] Based on a typical annual consumption of a Whistler residential customer consuming 90 GJ. This is also based on current commodity and midstream charges effective April 1, 2011.
[3] Based on a typical annual consumption of a Fort Nelson residential customer consuming 140 GJ. This is also based on current commodity charges effective April 1, 2011.

planned Procedural Conference proposed for May 24, 2011, are included in Section 8 of this Application titled Approvals Sought and Proposed Regulatory Process. The FEU are optimistic that the Commission will be in a position to make its determination regarding the type of hearing process, and the other issues identified, following the procedural conference proposed for May 24, 2011.

Request for Confidentiality

The FEU are submitting one component of the Application under separate cover requesting confidentially. In the Application, under Section 5.3.2.2 Labour Inflation and Benefits, certain paragraphs contain sensitive information which, if disclosed publicly, could compromise future negotiations between the Companies and their unionized labour bargaining units. The Companies are, therefore, submitting a redacted version of pages 147 and 148 for the public record.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachments

cc (email only): Parties to the FortisBC Energy Utilities 2010 and 2011 Revenue Requirements Applications

The FortisBC Energy Utilities

(comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.)

2012-2013 Revenue Requirements and Rates Application

Volume 1

May 4, 2011

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1 EXECUTIVE SUMMARY AND INTRODUCTION

With this Revenue Requirements Application ("RRA" or the "Application"), FortisBC Energy Inc. ("FEI" or "Mainland"), the Fort Nelson Service Area of FEI ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW" or "Whistler"), FortisBC Energy (Vancouver Island) Inc. ("FEVI" or "Vancouver Island") (together, the "Utilities", the "FortisBC Energy Utilities", the "Companies" or the "FEU") are requesting rate approvals for 2012 and 2013. Specific requests for each of the FortisBC Energy Utilities for 2012 and 2013, are summarized in this Section. In addition, the FEU are collectively applying for a Commission determination of the combined utility cost of service for 2013, subject to the Companies obtaining, at a later date, the necessary approvals to amalgamate. The combined cost of service will provide the basis for a unified rate structure for an amalgamated entity. A complete list of approvals sought for all utilities is set out in Section 8. The Companies believe that the proposed rates, and associated orders sought, are just and reasonable and should be approved pursuant to the *Utilities Commission Act* (the "UCA" or the "Act").

1.1 Executive Summary

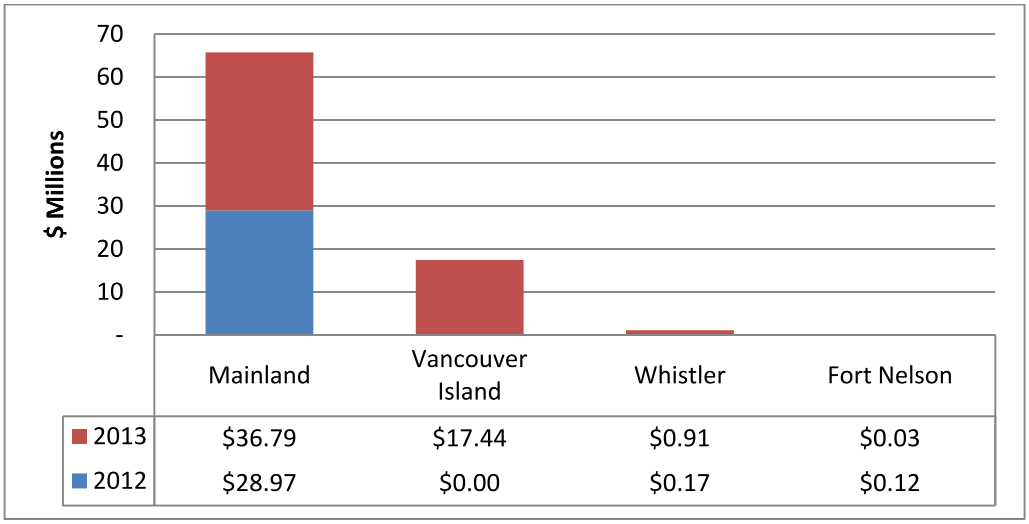
The FortisBC Energy Utilities remain focused and committed to providing cost effective, high-quality service to our customers, while ensuring employee and public safety, and operating in an environmentally responsible manner. In advancing these objectives, the FEU employs an appropriate management structure, a variety of metrics to assess corporate performance, and a compensation program that is tied to the achievement of objectives. The Companies' management structure, compensation philosophy and O&M and capital budgeting and control processes contribute to effective management of the costs that are incorporated into these revenue requirements.

This Application has been prepared using accounting policies and estimates assuming the continuation of the IFRS compliant policies that were approved in the setting of rates for 2011 for the Utilities. The accounting policy changes approved at that time are still allowed under IFRS, and are also allowed under US GAAP. Section 3.2 of this Application discusses the impacts on revenue requirements of either fully implementing IFRS but with deferral accounts, or adopting US GAAP.

The revenue requirements reflect all of the inputs in the financial schedules, and take into consideration all of the impacts described in this Application. The revenue requirement changes that the Companies are requesting are based on sound research and forecasting, using our knowledge and experience to determine what the Companies believe is the likely course of events over the upcoming forecast periods of 2012 and 2013.

The following Figure provides the 2012 and 2013 revenue deficiencies for the FortisBC Energy Utilities. The revenue deficiency is determined by comparing the forecast cost of service to the forecast revenue at existing 2011 rates for each year.

Figure 1.1-1: Forecast 2012 and 2013 Revenue Deficiencies for the FortisBC Energy Utilities[1]



The revenue deficiencies result in 2012 and 2013 delivery rate changes for Mainland, Whistler and Fort Nelson as shown in Table 1.1-1. There is no revenue deficiency in 2012 for Vancouver Island, as the forecast revenues at existing rates equal the forecast cost of service. In 2013, the forecast revenue deficiency is being offset by part of the projected December 31, 2012 surplus balance of $71.6 million (before tax) in the Rate Stabilization Deferral Account ("RSDA"). In this Application, Vancouver Island is seeking approval for a rate freeze for 2012 (which equals the forecast cost of service) and 2013.

Table 1.1-1: Mainland, Whistler and Fort Nelson Delivery Rate Increases[2,3]

Utility/Region	2012	2013	Total
Mainland	5.04%	6.36%	11.40%
Whistler	2.23%	11.90%	14.12%
Fort Nelson	6.51%	1.64%	8.15%

Overall, the primary drivers for the revenue deficiencies are in the four categories described below.

1. Rate base growth

Increases in rate base are a major driver of the revenue deficiencies for 2012 and 2013. The 2012 and 2013 rate base amounts represent the investment by the Companies in utility assets necessary to provide service to our customers. 95 percent of the total FEU rate base of $3.6

1 Section 7.1 to 7.4, Schedules 2 and 3

2 Approximate delivery rate change percent is equal to the revenue deficiency divided by the forecast delivery margin revenue at existing 2011 delivery rates (i.e. excluding cost of gas).

3 Section 7.1 to 7.4, Schedule 14

billion is comprised of net gas plant in service (gross plant in service, less contribution in aid of construction, less accumulated depreciation relating to both, and negative salvage). The remaining portion of rate base consists of:

- work-in-progress not attracting allowance for funds used during construction;
- the mid-year balance of unamortized deferral accounts (regulatory assets and liabilities);
- the thirteen-month average of cash working capital and other working capital;
- mid-year future income tax asset and offsetting liability; and
- in the case of the Mainland, the LILO benefit arising from LILO agreements with several Interior municipalities.

The table below sets out the forecast rate base for 2012 and 2013, for each FortisBC Energy Utility.

Table 1.1-2: Rate Base in 2012 and 2013

($ thousands) **Utility/Region**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 2,629,185	$ 2,736,507	$ 2,788,327
Vancouver Island	728,993	787,864	814,078
Whistler	42,594	42,139	41,502
Fort Nelson	6,839	8,889	9,127
	$ 3,407,611	**$ 3,575,399**	**$ 3,653,034**

The increases to rate base in 2012 and 2013 are a result of both regular capital expenditures, including the incremental capital related to the Long Term Sustainment Plan as discussed in section 1.2.4.3 below, and the implementation of large projects, such as the Mount Hayes LNG Facility, the Customer Care Enhancement ("CCE") Project, the Fraser River, Kootenay River, Muskwa River and Tilbury projects, and the recently approved Victoria Regional Operations Centre. Balances in the Energy Efficiency and Conservation and other deferral accounts are also significant contributors to changes in rate base. Offsetting these increases are reductions in Gas In Storage due primarily to lower commodity rates.

Increases to rate base increase the revenue deficiency primarily through the rate of return on assets and higher depreciation expense.

2. Increases to O&M (net of overheads capitalized)

O&M expenditures are influenced by a number of drivers with cost pressures coming from different sources including non-discretionary increases for inflation on internal labour and benefits, contracts and materials, increases in operating activities, and new business drivers and safety requirements. In particular, incremental funding requests are driven by the five cost drivers discussed in Section 5.2:

- Labour inflation and benefits;
- Codes and regulations spending, reflecting our continued focus on maintaining the safety and reliability of our system summarized in Section 1.2.4.1 and 1.2.4.2;
- Customer and stakeholder expectations, reflecting the in-sourcing of key customer service functions and meter reading cost increases in 2013 (summarized in Section 1.2.1), and also the implementation of our long term resource planning initiative;
- Demographic challenges; and
- Service standards and reliability, driven in part by our Long Term Sustainment Plan requirements summarized in Section 1.2.4.3.

The O&M increases due to each of these cost drivers are described in detail on a department-by-department basis in Section 5.2.

Offsetting these incremental funding requests in 2012, the Companies are forecasting savings as compared to 2011 from the implementation of the Harmonized Sales Tax ("HST"). A discussion of the ongoing uncertainty around the HST is included in Section 5.6 Taxes.

3. Increases in Other Revenue

Overall, the Companies are forecasting a significant increase in other revenue in 2012 and a further modest increase in 2013. For all of the FortisBC Energy Utilities, other revenue includes revenue from service work (connection charges), late payment charges, and returned cheques. In addition, the Mainland utility receives revenue for wheeling charges (from Vancouver Island), third party revenue on its Southern Crossing Pipeline, and starting in 2012, revenue from natural gas for transportation service. The Vancouver Island utility also receives revenue from the Mainland for LNG mitigation.

Increases in this area are mainly from our CNG and LNG service revenue as summarized in Section 1.2.3 below.

4. Other Changes in Revenue Requirements

In this category includes:

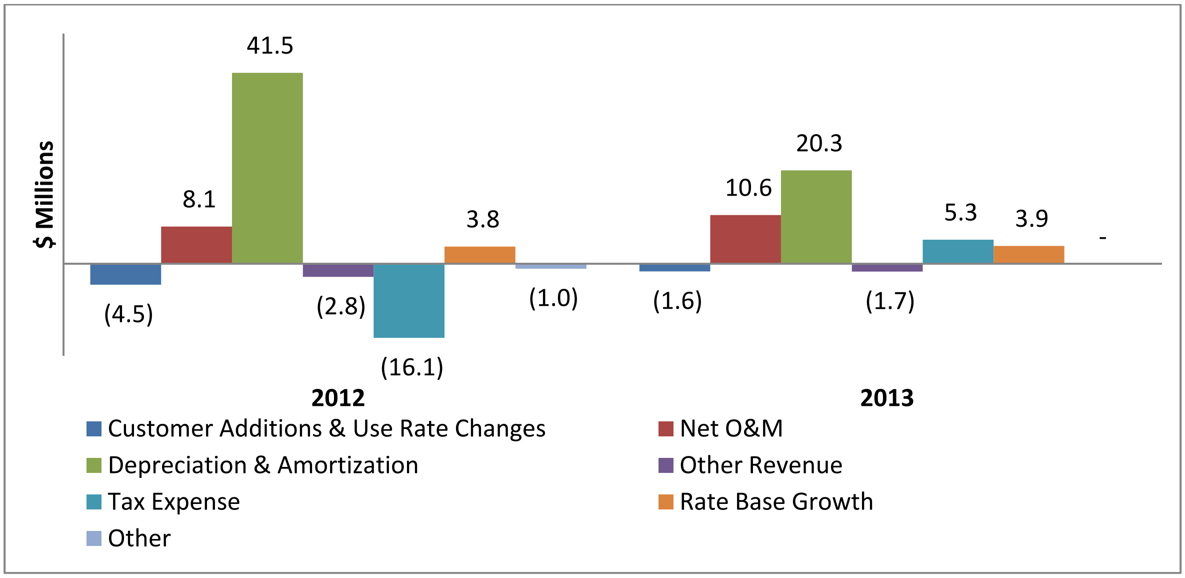
- Demand changes driven by customer growth and changes in use rates - all regions are forecast to experience a slight increase in consumption except Whistler, where consumption is forecast to decline by 1 percent from 2012 to 2013;
- Increases to depreciation and negative salvage rates related to removal costs - an update to the depreciation study has been conducted, resulting in increases in both depreciation expense and estimates of negative salvage;
- Increases in property tax. Property tax has a moderate impact on revenue requirements over the two year period; and
- Decreases in interest and income tax rates and changes to the tax treatment of certain items, such as removal costs. The income tax rate has declined from 26.5 percent in 2011 to 25 percent in 2012 and the forecast of short-term interest rates has declined from what was included in the 2011 rates.

The rates sought for each utility and the particular cost drivers affecting each utility are discussed in the following paragraphs. In addition to the delivery rate increases summarized below, with this Application FEI, Fort Nelson and FEW are also requesting changes to the Revenue Stabilization Adjustment Mechanism ("RSAM") Rider for 2012.

FORTISBC ENERGY INC.

Changes to the FEI revenue requirements result in revenue deficiencies of $29.0 million in 2012 and $36.8 million in 2013. These deficiencies are summarized in Figure 1.1-2 below.

Figure 1.1-2: Mainland Revenue Deficiency Components[4]



The primary drivers of the revenue deficiencies in FEI are rate base and depreciation growth resulting from the implementation of significant capital projects related to system integrity and reliability (including the Fraser and Kootenay River Crossings, the Tilbury Property Purchase and the capital related to the Long Term Sustainment Plan) and our customer care enhancement solution, as well as inflationary pressures on costs, a heightened focus on the safety and security of our gas systems, and our ongoing and growing compliance requirements related to codes and regulations. FEI has continued to manage its costs appropriately in the face of increasing cost pressures, and FEI believes that the costs reflected in the proposed rates are reasonable.

Based on these revenue deficiencies, FEI is seeking an increase in its rates for delivery service of 5.0 per cent in 2012, with an additional increase of 6.4 per cent in 2013 (cumulative increase of 11.4 per cent over two years). The delivery charge is only one component of a customer's total bill. For an average Lower Mainland residential customer, this delivery rate increase results in changes to the annual bill of 2.4 per cent or $24 in 2012 and an additional 3.0 per cent or $31 in 2013.[5] Including the removal of the Earnings Sharing Mechanism rider and an offsetting reduction to the RSAM rate rider, the FEI annual bill impact would be a larger increase, of 2.8 per cent or $28 in 2012.

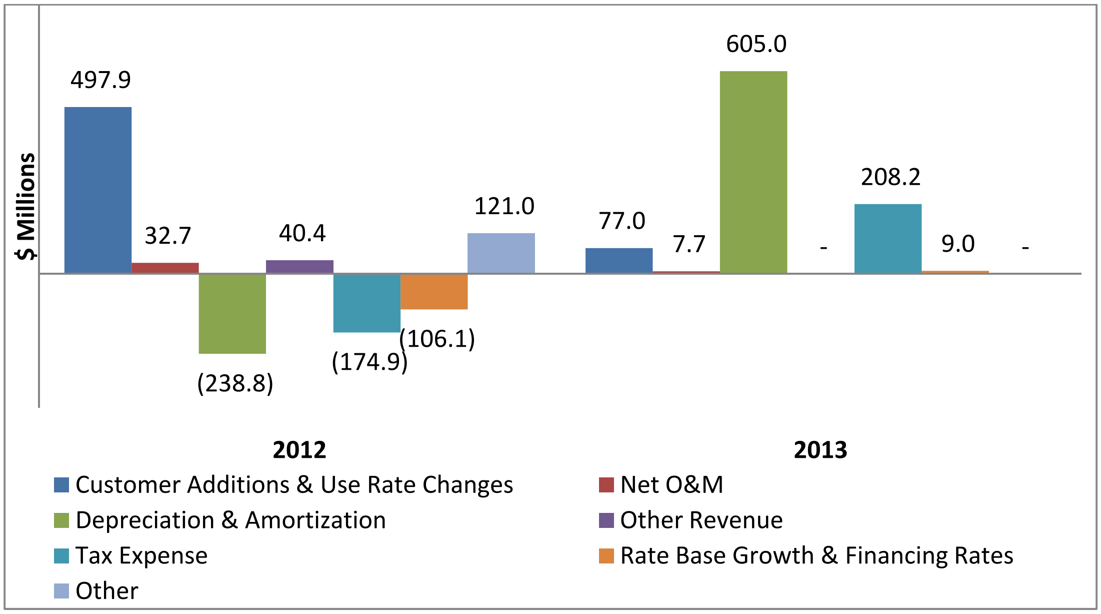
[4] Section 7.1, Schedule 1

[5] Based on a typical annual consumption of a Lower Mainland residential customer consuming 95 GJ. This is also based on current commodity and midstream charges effective April 1, 2011 and excludes the impacts of rate riders.

FORTISBC ENERGY WHISTLER INC.

Changes to the Whistler revenue requirements result in revenue deficiencies of $172 thousand in 2012 and $907 thousand in 2013. These deficiencies are summarized in Figure 1.1-3 below.

Figure 1.1-3: Whistler Revenue Deficiency Components[6]



In FEW, the primary driver of the revenue deficiencies is a reduction in the total demand forecast for 2012 and 2013, which is offset in large part in 2012 by the one year amortization of credit balances in deferral accounts.

Based on these revenue deficiencies, FEW is seeking an increase in its rates for delivery service of 2.2 per cent in 2012, with an additional increase of 11.9 per cent (cumulative increase of 14.1 per cent) in 2013. This results in an increase to the annual bill of an average Whistler residential customer of 1.5 per cent or $22 in 2012 and an additional 7.1 per cent or $115 in 2013.[7] Adding in the increase from the RSAM rate rider, the FEW annual bill impact would be an increase of 4.7 per cent or $69 in 2012.

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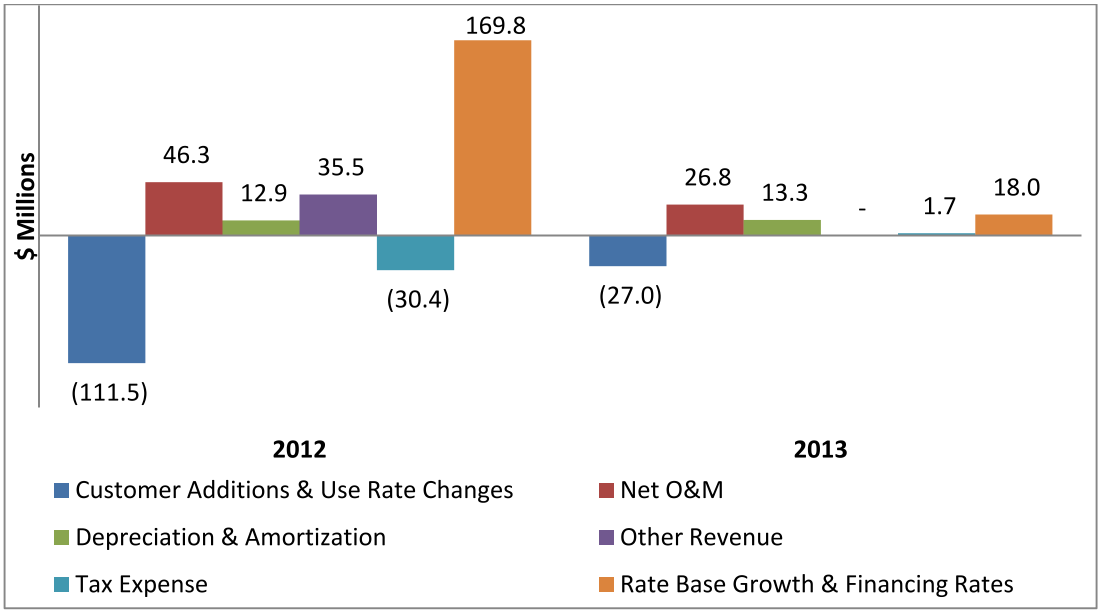
[6] Section 7.3, Schedule 1

[7] Based on a typical annual consumption of a Whistler residential customer consuming 90 GJ. This is also based on current commodity and midstream charges effective April 1, 2011 and excludes the impact of rate riders.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA

Changes to the Fort Nelson revenue requirements result in revenue deficiencies of $122 thousand in 2012 and $33 thousand in 2013. These deficiencies are summarized in Figure 1.1-4 below.

Figure 1.1-4: Fort Nelson Revenue Deficiency Components[8]



The primary driver behind the revenue deficiencies in Fort Nelson is the necessary replacement of the Muskwa River Crossing that is expected to be complete late in 2011. The cost estimate and in service date for this project remains as approved in Commission Order No. G-27-11.

Based on these revenue deficiencies, Fort Nelson is seeking an increase in its rates for delivery service of 6.5 per cent in 2012, with an additional increase of 1.6 per cent (cumulative increase of 8.2 per cent) in 2013. This results in an increase to the annual bill of an average Fort Nelson residential customer of 2.3 per cent or $26 in 2012 and an additional 0.6 per cent or $7 in 2013.[9] Including a reduction to the RSAM rate rider, the Fort Nelson annual bill impact would be an increase of only 1.8 per cent or $20 in 2012.

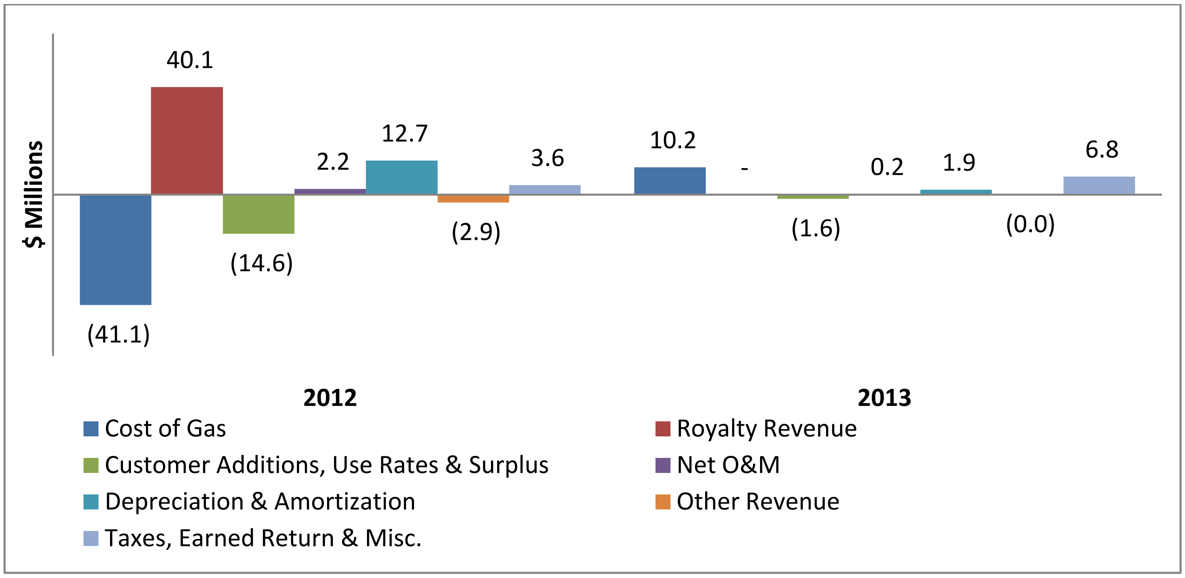
FORTISBC ENERGY VANCOUVER ISLAND INC.

A revenue deficiency is not forecast for 2012 for Vancouver Island; the $40.1 million deficiency that results from the loss of royalty revenues is offset by a $33 million reduction in the cost of gas and $8.1 million in amortization of the Gas Cost Variance Account ("GCVA"). The revenue

8 Section 7.4, Schedule 1
9 Based on a typical annual consumption of a Fort Nelson residential customer consuming 140 GJ. This is also based on current commodity charges effective April 1, 2011 and excludes the impact of rate riders.

deficiency in 2013 of $17.4 million is attributable to an increase in the cost of gas, the removal of the one-year amortization of the GCVA, and tax expense and earned return increases, as displayed in Figure 1.1-5.

Figure 1.1-5: Loss of Royalty Revenues Offset by Reduction in Cost of Gas in 2012[10]



FEVI is seeking to maintain current rates for all customers except those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012. Consistent with the intended purpose of the RSDA, FEVI proposes to use part of the surplus to maintain rates at the 2011 level for 2013. The RSDA was approved as part of the last FEVI revenue requirements application, with the intention of using the accumulated balance to manage cost pressures unique to FEVI. The rate proposal in the present Application implements the previously developed strategy.

THE FORTISBC ENERGY UTILITIES - COMBINED COST OF SERVICE FOR 2013

Later this year, the FEU intend to seek the necessary approvals to amalgamate effective January 1, 2013 and to introduce harmonized rate structures effective on the same date. As the anticipated effective date of amalgamation and harmonized rates falls within this two year revenue requirements period, the orders sought in respect of 2013 rates for the individual entities have been expressed as being conditional upon amalgamation and harmonized rates not taking effect. And, in anticipation of the upcoming application to amalgamate and introduce harmonized rates, the FEU are collectively applying in the present Revenue Requirements Application for approval of the amalgamated utility cost of service for 2013. The FEU believe that this is the most efficient way to proceed and the order approving an amalgamated cost of

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[10] Section 7.2, Schedule 1

service can be made without predetermining the merits of amalgamation and harmonized rates. Further information on the requested approval of an amalgamated cost of service, and the intended next steps to achieve harmonization of rates, is included in Section 1.2.5.

In addition to the revenue deficiency drivers described above, FEU has included in the Introduction Section (1.2) below, a review of important initiatives that the Companies are pursuing, such as enhanced Energy Efficiency and Conservation programs (Section 1.2.2), expanded service offerings for customers (Section 1.2.3) and the first step towards harmonization and an amalgamated rate structure (Section 1.2.5).

1.2 Introduction

The FEU collectively form the largest natural gas distribution utility in BC, providing sales and transportation services to approximately 950,000 customers in more than 140 communities throughout the Province. The Utilities have a proven record of offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

The currently approved rates for the Mainland, and for FEVI, were determined through a Negotiated Settlement Process ("NSP") for 2010 and 2011. The 2010 and 2011 rates for FEW and the 2011 rates for the Fort Nelson division of FEI were determined through oral and written hearing processes, respectively. These recent rate setting processes and other more recent regulatory proceedings laid the foundation for the Utilities to deliver on several initiatives. These included:

1. The in-sourcing of key customer service functions;
2. Enhanced Energy Efficiency and Conservation programs;
3. Expanded service offerings for customers, including:
    1. A two year trial period for a biomethane service offering;
    2. A business model and rate design for Compressed Natural Gas ("CNG") and Liquefied Natural Gas ("LNG") fueling service filed December 1, 2010; and
    3. Approval to pursue Alternative Energy Services (which the Companies are now referring to by the more descriptive name "Thermal Energy Services") within the utility.
4. Increased focus on investments to maintain the safety and reliability of our system; and
5. The development of an interim rate mitigation strategy for our customers on Vancouver Island.

Each of these priorities and how they have been addressed in this RRA are discussed separately below.

1.2.1 IN-SOURCING OF KEY CUSTOMER SERVICE FUNCTIONS

In Commission Order No. C- 1-10, FEI received approval to in-source key components of customer care services and implement a new Customer Information System ("CIS") through the Customer Care Enhancement Project ("CCE Project"). The CCE Project is progressing on time with an implementation date of January 1, 2012, and the overall project spend remains on track with no variance to the approved spend of $115.5 million.

As a result of the implementation of the CCE Project, the Customer Service department has been created to manage the contact centres (located in Burnaby and Prince George), the revenue cycle and billing operations, customer relations, bad debt expenditures, and meter reading services. Overall, the 2012 forecast costs for the Customer Service department show a decline of approximately $1.9 million from the 2011 approved amount, as savings are recognized with the transition to the in-sourced service delivery model. In Section 5.3.7 of this Application, the ongoing services and operating expenses for the Customer Service Department are described in detail, as well as the Utilities' plan to maintain existing service quality measures for the two years of this RRA.

Also, in Section 6.3, a deferral account is requested to capture actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for many of the Customer Service functions. The types of uncertainties that the deferral account will address include fluctuations in call volumes, the rate of customer adoption of new communication channels and self serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, and any variances in the anticipated duration required for new staff to become skilled and proficient at their responsibilities. The variance account will also capture spending variances in meter reading costs primarily due to the timing of BC Hydro's Smart Metering Initiative and its impact on joint gas/electric meter reads in 2012 and the uncertainty of costs in 2013. These cost variances are largely beyond the control of the Companies and the use of deferrals will avoid the potential for windfall gains or losses to customers or the shareholder during the transition period.

1.2.2 ENHANCED ENERGY EFFICIENCY AND CONSERVATION PROGRAMS

As part of the 2010-2011 RRA, FEI and FEVI received approval to increase their investment in Energy Efficiency and Conservation ("EEC") to add programs for Interruptible Industrial customers and Innovative Technologies, to reallocate funding to Affordable Housing initiatives, and for additional funding to implement programs until the end of 2011, and an extension of the funding approved by the Commission in the EEC Decision of April 2009. This brought the total funding for EEC activities to $31.0 million in 2010 and $35.3 million in 2011. Of this approved expenditure, FEU spent $12.6 million in 2010 and is projecting to spend $25.7 million in 2011.

The 2010 Conservation Potential Review ("CPR") identified significant potential for EEC programs see Appendix K-2, and supports an expansion of EEC initiatives for the benefit of customers. In this Application the FEU are proposing an increase in the allowed funding envelope for 2012 and 2013 to $74.5 million in total for each year. This increase consists of increased budgets for previously-approved program areas (including "conventional" EEC programs and funding for Innovative Technologies), expansion of EEC programs to the Whistler service area, offering industrial programs to FEVI customers, as well as new initiatives such as the Furnace Scrap-It Program.

The amounts requested for 2012 and 2013 represent a significant increase in the funding envelope relative to 2011. However, the increased amount is supported by the CPR and all expenditures will continue to be evaluated according to Commission-approved mechanisms to ensure that they are beneficial. Also, the FEU are proposing a change in the methodology for recovery of EEC expenditures from customers such that only a base level of spending ($20 million per year) is included in rate base for 2012 and 2013. Expenditures incurred over and above the base level will be placed in a non rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014. The change in methodology is discussed in Section 6.3.2.1, and the details of all planned EEC expenditures are included in Appendix K-1. The FEU believe that the approach of increasing the overall funding envelope for cost-effective programs, while establishing the proposed financial treatment best ensures that FEU can maximize the benefits of EEC programs for customers in a manner that is fair to customers and the Companies.

FEU's ultimate intention is to obtain approval for a long term funding request. The FEU's long term EEC funding request for 2014 and beyond will be made in the FEU Long Term Resource Plan that will be filed with the Commission in 2013. The approvals sought in the present Application will provide the necessary continuity until that long-term request can be made.

1.2.3 EXPANDED SERVICE OFFERINGS FOR CUSTOMERS

The FortisBC Energy Utilities are providing expanded service offerings for customers in the areas of Biomethane, CNG and LNG Fueling, and Alternative Energy Services (now being referred to in this Application by the more descriptive term "Thermal Energy Services"). The costs and revenues associated with the Biomethane and Natural Gas for Transportation programs form part of FEI's natural gas business, and have been included in the forecasts included in this Application. In FEI's 2010-2011 Revenue Requirements Application, the necessary accounting structures were put in place to separate FEI's Thermal Energy Services line of business from the natural gas business. As a result of the approval of that application for FEI, the activities in the area of Thermal Energy Services are captured in a non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. As a result, there is a reduction in the O&M included in the natural gas cost of service that is associated with the recovery of overheads from the Thermal Energy Services line of business. In the long-run, the more successful the Thermal Energy Services business becomes, the greater the potential benefit to natural gas customers in terms of a recovery of overheads. Each of the three service offerings is discussed below.

1.2.3.1 Biomethane Service Offering

In Commission Order No. G-194-10, FEI received approval to implement a two year pilot program for a Biomethane Service Offering. In that order, FEI was directed to include in this RRA the details of costs for the program.

The planned launch of the Biomethane Service Offering is June of 2011. FEI has included the costs and related revenues for the Biomethane program for 2012 and 2013 in the O&M (Section 5.3), capital expenditures (Section 6.2). The rate base deferral for the 2010-2011 Biomethane Program Costs (Section 6.3) is also included in the revenue requirement calculation. In addition, FEI has included a comprehensive report in Appendix J summarizing the costs incurred and deferred in 2010 and 2011 related to the program, and also providing a summary of the forecast program costs and revenues that are included in each of Sections 5.3, 6.2 and 6.3. Section 6.3 includes a description of the 2010-2011 Biomethane Program Costs deferral account, and Appendix G includes a description of the Biomethane Variance Account. In general the costs are as expected. The only change was a result of a redesign to the upgrader for the Columbia Shuswap Regional District biomethane supply project.

FEI will file a Biomethane Report in December 2012 to comply with the Order No. G-194-10 to initiate the review of the two year pilot program. Although this review will be commencing part way through the two-year test period for this RRA, FEI is of the view that it is reasonable to forecast costs through 2013 as any outcome from this review will not be resolved until sometime in 2013. Further, customers who elect to take up the Biomethane Service offering from FEI would expect this service to continue through 2013 and beyond given that they only signed up for the service beginning in June of 2011. FEI continues to believe the business model that has been approved by the Commission in Order No. G-194-10 is robust and comprehensive and can deliver this service offering to customers through the utility business.

1.2.3.2 Natural Gas Vehicles

On December 1, 2010 FEI submitted its Application for Approval of a Service Agreement for CNG Service and for Approval of General Terms and Conditions ("GT&Cs") for CNG and LNG Service (the "NGV Application") to the Commission. The NGV Application contemplates a model for FEI to own and operate refuelling stations for natural gas vehicle customers in a manner which ensures that all FEI customers benefit from the increased system throughput resulting from NGV volumes, while ensuring that the forecast incremental costs of FEI owning and operating these stations are recovered through a contract rate charged to these incremental customers. The proposed rate structures require firm "take-or-pay" (i.e. minimum contract demand) commitments, with rates set to recover from the particular customer over the term of the service agreement the cost of investing in and maintaining CNG/LNG facilities located on the customer's property to permit fueling. FEI is targeting commercial, return-to-base fleet of buses, heavy duty trucks, vocational trucks, and marine vessels. Under this business model the benefits to existing customers are potentially significant and this market represents one of the best opportunities to add throughput to FEI system.

On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval. Given customer support[11] for the NGV Application and our belief that this is part of our core business, we have included in this RRA our project costs and revenue to undertake this business for 2012 and 2013. Thus these impacts have been integrated into our other revenue forecasts (Section 5.5), O&M (Section 5.3), capital expenditures (Section 6.2) and rate base deferral (Section 6.3) for the 2011 CNG and LNG Service Costs and Recoveries.

In the recent NGV Application, FEI requested approval for an ongoing rate base deferral account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. Further, in this Application, FEI is seeking approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16 of $2.9 million in 2012 and $4.4 million in 2013. FEI has included a comprehensive report in Appendix I summarizing the costs incurred and deferred in 2010 and 2011 related to the program, and also providing a summary of the forecast program costs and revenues that are included in each of Sections 5.5, 5.3, 6.2, and 6.3.

The forecasts made in relation to NGVs and NGV fueling infrastructure in this Application and in Appendix I are premised on the assumption that the NGV Application will be approved as filed and all approvals sought will be granted. The forecasts are further premised on the assumption that the cost-effective EEC incentives for NGVs will continue during the test period of this RRA. These EEC incentives are being reviewed under a current proceeding as per Commission Order G-70-11, with the Information Request process beginning on May 4th, 2011. The growth of the NGV fueling business is inherently reliant upon the adoption of NGVs in our service territory and the Utilities believe that the adoption of NGVs in our service territory is inherently reliant upon the continued availability of these EEC incentives for NGV adoption during the term of the revenue requirement. The Utilities wish to make clear that the provision of cost-effective EEC incentives to fleet operators is not pre-conditioned on any requirement that the Utilities own and operate the NGV refuelling stations to supply the acquired vehicles. It does however require that it be allowed to make that option available to prospective fleet operators in order to see the NGV adoption required to provide meaningful and material benefit to our existing customers. Discontinuance of EEC incentives for NGV's will represent a significant barrier to achieving the objective of adding NGV throughput to the system for the benefit of all existing customers.

1.2.3.3 Thermal Energy Services

FEI and FEVI, in their respective 2010-2011 Revenue Requirements Applications, requested approval of tariff provisions to permit them to provide Alternative Energy Solutions ("AES"), which included Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the applications. The Companies are now using the more descriptive term "Thermal Energy Services" to encompass these same services. The Negotiated Settlement

[11] Final Submission Arguments from Registered Interveners BCSEA, BCOAPO, and CEC generally support the proposed NGV Application.

Agreement for FEI's 2010-2011 RRA, approved by BCUC Order No. G-141-09, acknowledged that FEI would be engaged in Thermal Energy Services (or AES). The Negotiated Settlement Agreement for FEVI's 2010-2011 RRA, approved by BCUC Order No. G-140-09, acknowledged the fact that FEVI withdrew its requests for relief in the RRA relating to AES and the Parties acknowledged that FEI will be pursuing AES projects within the FEVI service area and agreed that the costs incurred by FEI to provide AES will not be recovered in FEVI's natural gas service rates.

The Commission's approval of the FEI NSA resulted in an approved Rate Schedule for Thermal Energy Services, and implemented the necessary terms and certain conditions to establish Thermal Energy Services as a distinct line of business within FEI. Some of the conditions included in the approved NSA were as follows:

> *"Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates.*
>
> *The Parties agree that the costs incurred by TGI to provide AES should not be recovered as part of natural gas service rates, and visa versa. The Parties agree that TGI's proposed New Energy Solutions Deferral Account, attracting AFUDC, is an appropriate mechanism to address allocation issues as between TGI's gas customers and TGI's AES customers. Therefore, the Parties agree that the new Energy Solutions Deferral Account will remain in effect pending a future rate design application at an unspecified future date after 2011 and will capture and record the following (plus AFUDC) to be recovered from AES customers:*
>
> > *(a) Direct costs associated with AES projects as outlined on pages 267-268 of the Application, including cost of design, equipment, etc. constructing and financing; and*
> >
> > *(b) Sales and marketing O&M and other development costs will be directly charged to the deferral account by time sheets or other direct charge (estimated at $1.0 million in 2010 and $1.5 million in 2011, representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011); and*
> >
> > *(c) An appropriate overhead allocation, which the parties have agreed will be $500,000 in each of 2010 and 2011 (representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011).*
>
> *Revenues received from customers for all AES projects, which are based on contracts approved by Commission will be recorded in the AES deferral account.*
>
> *The risk of non-recovery of amounts in the New Energy Solutions Deferral Account will not be borne by natural gas ratepayers. The Parties agree that any debit balance in the New Energy Solutions Deferral Account will not be recovered through natural gas rates and any credit balance will not be applied to reduce natural gas rates…"*

FEI is making progress towards developing the Thermal Energy Services line of business. It is expected that FEI will be bring forth individual projects with signed contracts for Commission approval during the Spring and Summer of 2011 that will also meet the terms of the NSA. Consistent with the approved framework, forecast costs for 2012 and 2013 relating to Thermal

Energy Services have been segregated and allocated to the Thermal Energy Services line of business. FEI activities in the area of Thermal Energy Services will continue to be captured in the approved non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. There is also a reduction in the O&M included in the natural gas cost of service (i.e. a benefit to natural gas customers) that is associated with the recovery of overheads from the Thermal Energy Services line of business. This is discussed further in Appendix G.

The growing prevalence of thermal solutions such as solar, DES and geo exchange, regardless of the provider of those services, will have an increasingly significant impact on the natural gas requirements over time. Thus, from the perspective of natural gas customers it is important to understand the growth of these energy alternatives over time and how they may impact the natural gas throughput and utilization. FEU sees this as an important issue to address in future filings such as the Long Term Resource Plan and future Rate Design applications. The need for additional resources to examine these impacts as part of the long term integrated resource planning process is discussed further in Section 5.3.8.

1.2.4 INCREASED FOCUS ON INVESTMENTS TO MAINTAIN THE SAFETY AND RELIABILITY OF OUR SYSTEM

In our 2010-2011 RRAs, we requested increases to O&M and capital budgets to ensure ongoing compliance to existing codes and anticipated new or changed codes and to allow us to continue to invest in the safety, integrity and reliability of the energy delivery system. To address these requirements, we received approval for additional O&M in the amount of $5.3 million in 2010 and a further $2.1 million in 2011. This funding allowed us to enhance safety messaging for customers, begin the long-range asset planning and address the specific code changes that were required. How each of these three areas has evolved since then is discussed below. The FEU believes that continued funding in these areas is necessary to ensure safe and reliable natural gas service.

1.2.4.1 Codes & Regulations

In addition to the codes and regulations that were addressed in 2010 and 2011, the FEU have identified new codes and regulations, and changes to existing codes and regulations that need to be addressed. A further discussion of these specific codes and regulations and incremental funding of $1.8 million in 2012 and a further $0.9 million in 2013 to address these requirements is included in O&M Section 5.3.

Two other areas where the Utilities need funding to address safety and system integrity are:

- The BCOneCall project - a multi-stream two and a half year project that will automate a portion of the BCOneCall process and allow for the realization of significant benefits immediately upon completion of the project; and

- The Gas Assets Project - a four year project to move historic gas system asset compliance records into one system, with three distinct phases which will improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records, and the retention and disposal of compliance records no longer needed for operational, or other requirements.

Each of these two significant projects is discussed further in the Rate Base Deferrals Section 6.2.

1.2.4.2 Safety Messaging

In 2010 and 2011, the FEU spent approximately $1.0 million on safety awareness, primarily to increase the public's awareness of how to identify and respond to a gas leak. This initiative requires additional funding in 2012 and 2013 to fully implement our gas odour and action safety messaging, and also to increase public safety education around excavation diligence. The details regarding our plans to spend an additional $750 thousand in 2012 and a further $100 thousand in 2013 are included in O&M Section 5.3.8.5 Energy Solutions and External Relations.

1.2.4.3 Long Term Asset Planning

FEU recognized the need to develop a long term life cycle view of gas assets when planning its sustainment capital and related asset management programs a number of years ago and first described these requirements in their 2010-2011 Revenue Requirements Application and 2010 Resource Plan. A long term view of gas assets is required primarily because of risks related to aging infrastructure. Complicating this planning requirement is the continual need to also address environmental responsibility, increased public expectations and increased regulations to maintain the safety, reliability and integrity of the distribution and transmission system used to provide gas delivery service. Critical in this regard is the concept of a "Long Term Sustainment Plan", which serves as a key component of FEU's approach for managing this challenge. This approach to long term planning is also important in order to ensure that any transmission and distribution system changes are cost effective so that their impact on customers' rates is kept to a minimum.

Today, FEU is responsible for managing gas transmission and distribution assets with a book value of approximately $3.0 billion and an approximate replacement value of $6.8 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40 to 55 years. These aging assets face an increasing rate of deterioration as they approach the end of their service life. FEU anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

To successfully manage this coming wave of asset replacements, FEU must also be cognizant of other interrelated factors. A long term view of asset management is therefore required due to a number of reasons:

- customers expect natural gas to be there when they need it. Tolerance for service disruption due to inadequate planning on the part of the utility is understood to be limited;
- codes and regulations are becoming increasingly stringent with the natural gas delivery system operator being held to higher standards of reliability, safety and environmental stewardship;
- the increased focus on public safety has recently been seen in the response to a pipeline rupture and subsequent fire in San Bruno, California which has resulted in the introduction of a number of initiatives to increase the onus on the operators to ensure public safety. Asset failure that impacts public safety is not acceptable;
- significant rate increases due to costs of repairs and unanticipated asset replacements passed on to customers would not be in the best interest of the customers, especially if they come in large spikes as significant assets fail and require immediate replacement;
- the wave of asset replacement poses the challenge of mobilizing additional O&M and capital resources. Additional O&M resources are required to enhance the asset management practices needed to manage aging infrastructure. Capital resources are needed to procure material, equipment, services, labour and contractors for the execution of asset replacement; and
- municipalities and utilities across North America are starting to come to grips with aging infrastructure and how to maintain services to their customers. This need, combined with baby boomers retiring, is resulting in resource shortages across the continent. Adequate lead time and visibility of asset replacement programs is required in order to engage contractors so that resources can be successfully mobilized when they are needed.

FEU expects system sustainment costs to continue rising in the future given the extent of its aging infrastructure and because of the complexity of the interrelated factors described above. To help manage these increasing costs, ensure system integrity, address risk to public safety and property and continue to reliably deliver service, FEU is developing a Long Term Sustainment Plan (“LTSP”).

The LTSP includes enhancements to our asset management and system integrity processes. The cost to establish these enhancements are included as a key component of the incremental O&M funding requested in Section 5.3 of this Application. Instead of identifying asset replacement requirements on a reactive basis and with a limited view beyond a three to five year horizon, and potentially overlooking major projects that address high risks, a higher level of resources is needed to complete the comprehensive reviews and analyses that are required to support long-term capital expenditure commitments of the amounts anticipated after 2013.

In Section 6.2, FEU describes sustainment capital spending for a total of $82.3 million in 2012 and $89.6 million in 2013 that it seeks approval for. These forecast amounts represent incremental spending, excluding CPCN projects, of $23.0 million and $30.2 million in 2012 and 2013 respectively over 2011 approved amounts for the same purpose. FEU believes that the forecast expenditures strike an appropriate balance between the risks to health, safety, system integrity, and property, with rate impacts and many other factors.

Over the longer term, FEU will continue to improve its asset management practices with the further development of a Long Term Sustainment Planning process. The LTSP will help us analyze a myriad of factors impacting asset replacement decisions and be used to prioritize spending where necessary and help to minimize the impact on rates by spreading costs out over time.

In summary, FEU must continue to address the critical issue of aging infrastructure and asset management in an evolving business environment. FEU believe the programs and expenditures included in this RRA are prudent and in the best interest of customers.

1.2.5 RATE MITIGATION STRATEGY FOR VANCOUVER ISLAND: AMALGAMATION AND HARMONIZED RATE STRUCTURE

In the 2010-2011 RRA for Vancouver Island, we developed and received approval for an interim rate mitigation strategy to help to offset the immediate rate pressure that would otherwise result from the loss of the forecast $40 million of revenues (“Royalty Revenues”) provided to FEVI by the Provincial Government that partially offset the cost of gas on Vancouver Island. This interim strategy resulted in a rate freeze for core market customers at a level that exceeded the cost of service and the creation of a Rate Stabilization Deferral Account, to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The balance in the RSDA would then be used after 2011 to offset future rate increases. However, the balance in the RSDA is insufficient to offset the increased rate pressure for more than a short period of time. FEVI has long recognized that a permanent solution is required, and that the real solution will take the form of amalgamation of the Companies and the implementation of a harmonized rate structure. FEU’s intention is to file an application in the Fall of this year seeking approval to amalgamate the Companies effective January 1, 2013 and approval of a harmonized or “postage stamp” rate structure.

In this Application, we have presented the revenue requirement information for each of the FEU separately for 2012 and 2013, and are seeking approval of rates for each company separately. FEVI’s revenue requirement for 2013 reflects the utilization of part of the RSDA balance. However, as the intention is to amalgamate the entities half-way through the RRA period, the FEU have also taken the additional step in this Application of presenting an amalgamated cost of service based on the assumption that the three companies will be amalgamated effective January 1, 2013. The Companies are seeking approval of the amalgamated cost of service, which would only be employed if and when the FEU later obtain the necessary approvals to amalgamate and to implement harmonized rates. The amalgamated cost of service, once determined in this Application, will form the base for the cost of service used in developing a harmonized rate structure.

In this section, the FEU set out in greater detail our future plans for amalgamation and postage stamp rates, and how the approvals sought in the present Application fit within those plans. The FEU believe that it enhances regulatory efficiency to address the issues relating to the cost of service under an amalgamation scenario as part of the present Application, without predetermining the merits of amalgamation or a harmonized rate structure. This approach will ensure that the future rate design for an amalgamated entity can be assessed in a subsequent rate design application based on known 2013 costs.

The remainder of this section is organized as follows:

- Section 1.2.5.1 explains why the FEU intend to submit an application for approval to amalgamate, in conjunction with the adoption of postage stamp rate structures across the combined service area.
- Section 1.2.5.2 outlines our rationale for seeking approval as part of the present Application of an amalgamated cost of service for 2013, in addition to the rate approvals sought on a company by company basis for 2012 and 2013.
- Section 1.2.5.3 sets out, at a high level, our intention to implement postage stamp rates in two phases, the first of which (the "Phase "A" Rate Design Application") will be addressed in conjunction with amalgamation in Fall 2011 to determine rates effective on January 1, 2013 based on the approved amalgamated cost of service.

1.2.5.1 Rationale for Applying in Fall 2011 for Approval to Amalgamate and Postage Stamp Rates

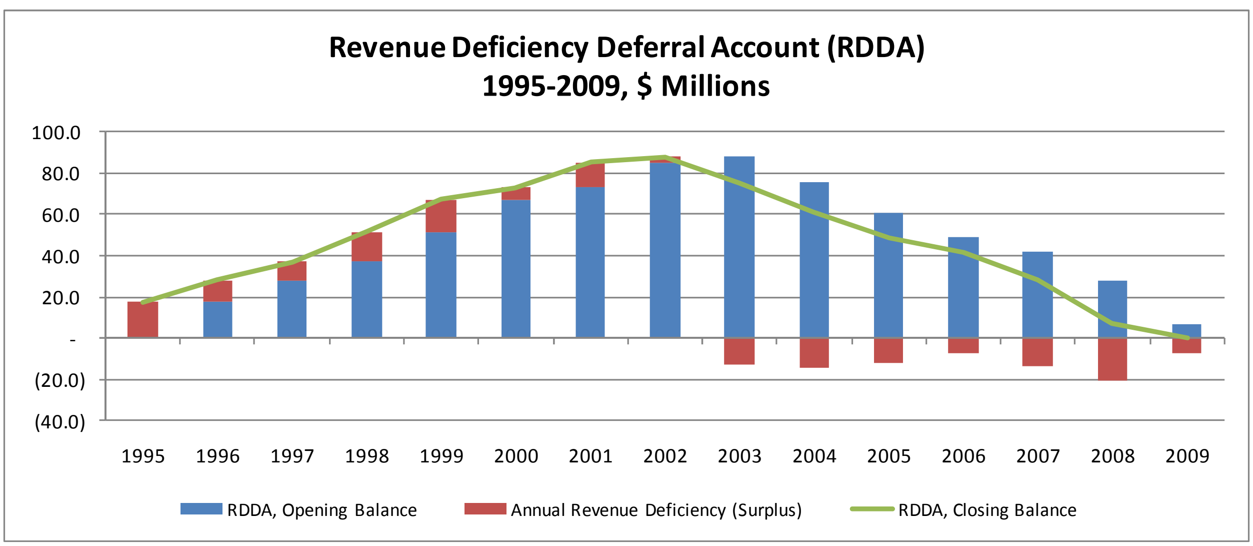
FEU discusses below the pressing challenge caused by the existing rate differential and future upward pressure on rates paid by customers on Vancouver Island, and how amalgamation of the three Utilities in conjunction with moving to postage stamp rates, presents a lasting solution to these issues. FEW also faces competitive challenges. The explanation provided below is intended to help explain why FEU has sought approval of an amalgamated cost of service for 2013 as part of this Application. FEU will be providing its full justification for amalgamation when it submits its Amalgamation and Rate Design Phase 'A' Application this Fall. FEU believes that detailed inquiries about the rationale for amalgamation should be made in the context of FEU's Amalgamation and Rate Design Phase 'A' Application and that the Commission's approval in the present Application of an amalgamated cost of service for 2013 can be made without prejudging the merits of amalgamation and postage stamp rates.

FEVI CUSTOMERS FACE SIGNIFICANT RATE INCREASES

From the outset of the utility on Vancouver Island, it was recognized that the relatively high cost structure and small customer base would present challenges to FEVI being able to compete with alternative energy sources. At that time, a series of agreements were put in place among the utilities (at that time, it was actually two distinct transmission and distribution utilities), and the Federal and Provincial governments, in conjunction with a new Vancouver Island Natural Gas Pipeline Agreement Special Direction ("Special Direction"). Those agreements and the Special Direction put in place mechanisms that would help to allow the utility to remain competitive. Rates were set below the cost of service, and the revenue deficiency was captured in the Revenue Deficiency Deferral Account ("RDDA"). The cost of gas was partially offset by Royalty Payments paid by the Provincial government. The Royalty Revenues, which have served to offset part of the cost of gas paid by customers, were a critical component in the development of a viable utility on Vancouver Island. However, these mechanisms had a limited horizon. Under the Special Direction, the RDDA was to be recovered over the shortest time reasonably possible taking into account FEVI's competitive circumstances. The Royalty Revenue payments are discontinued at the end 2011. The cessation of those payments will impact customers through higher rates unless something is done to address it. The current Vancouver Island rate differential for a Residential customer is approximately $6.00 per GJ or approximately 60 percent greater when compared to the effective rate of a Rate Schedule 1 customer in the Lower Mainland. This rate differential will continue to increase in the absence of rate mitigation on Vancouver Island.

The RDDA grew to a balance of $87.9 million in 2002. Beginning in 2003 FEVI paid down the balance in the RDDA, reducing it to zero in 2009.

Figure 1.2-1: RDDA Balances and Annual Repayments



Nevertheless, the pending end to the Royalty Revenue payments has loomed large for FEVI and its customers, as the cessation of those payments still presented the potential for significant and immediate rate increases in 2012, all else equal, of approximately 20 percent.[12] A rate increase of this magnitude would have compounded the competitive challenges facing FEVI. As a result, in its 2010-2011 RRA/RDA, FEVI proposed a rate freeze for 2010 and 2011. FEVI's proposal to freeze rates was accepted in the Negotiated Settlement Agreement, which was approved by the Commission.[13] The approved rates for 2010 and 2011 over-recovered the cost of service during the period (since they had been set in prior years to recover the RDDA, which had now been paid off), and the surplus revenue for 2010 and 2011 was placed into a deferral account, the RSDA. The intention was to use the revenue surplus to help mitigate any revenue requirement increase with the loss of the Royalty Revenues in 2012 and the repayment of the remaining Repayable Contributions.[14] Following the logic of the approved RSDA mechanism, in this Application FEU is proposing a rate freeze for FEVI sales customers, as well as FEW and BC Hydro[15] for 2012 and 2013 (please refer to Section 3.4.2 for a detailed discussion). The proposed rates for 2013 are insufficient to recover the full forecast cost of service in that year, and part of the surplus in the RSDA is used to make up the shortfall in each year.

While there is sufficient surplus in the RSDA to cover the forecast revenue shortfall resulting from the proposed rates in 2013, this mechanism provides only a temporary solution. Although somewhat mitigated by reductions in the forecast cost of gas, there is upward pressure on FEVI's cost of service post-2012 for the foreseeable future due to the cessation of the Royalty Revenue payments. Figure 1.2-2 provides a 5 year outlook of FEVI cost of service rates and shows an expected rate increase of 20 percent by 2016, as compared to existing 2011 rates. Two scenarios providing variations in gas costs are also shown in Figure 1.2-2 and demonstrate that in the event that high commodity costs are experienced, the expected rate increase doubles to 40 percent by 2016.[16]

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12 All else equal, the impact to delivery rates would be the 2011 royalty credits of $40.091 million as approved in Commission Order No. G-140-09.

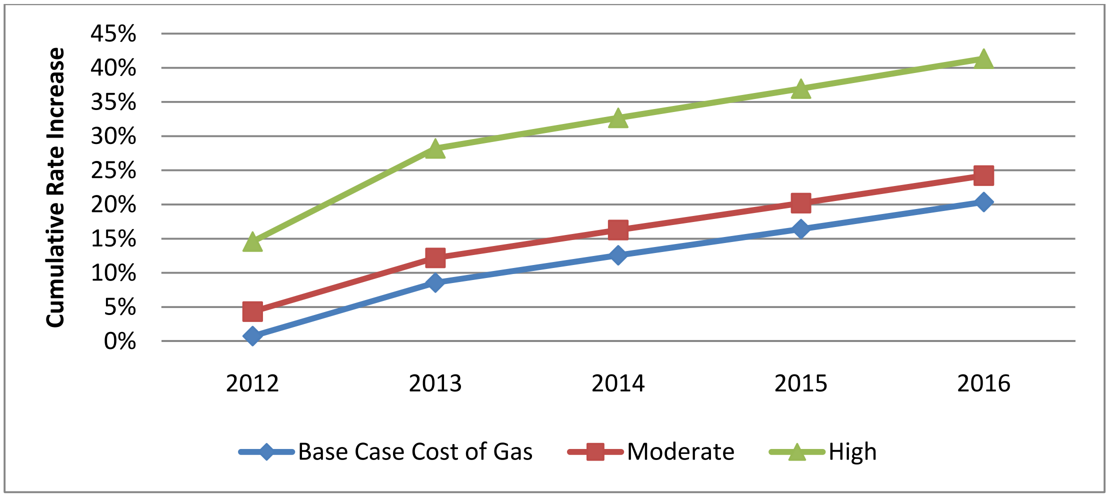
13 BCUC Order No. G-140-09 approving the Negotiated Settlement Agreement for FEVI pertaining to its 2010 and 2011 Revenue Requirement and Rate Design Application, Part II, Items 22-24.

14 As discussed in Part II of the FEVI 2010-2011 RRA/RDA, FEVI is obligated under the Pacific Coast Energy Pipeline Agreement ("PCEPA") to repay a total of $75 million to the Federal and Provincial Governments that had been provided to the Company under the terms of an earlier agreement that had been entered into to support the construction of the pipeline to Vancouver Island and the Sunshine Coast. The forecasted Repayable Contributions expected to be remaining at the end of 2012 is $29.1 million and $25.0 million at the end of 2013.

15 Other Transportation customers (VIJV and Squamish) are on contract rates.

16 Base Case Cost of Gas scenario has an approximate weighted average cost of gas of $6.30/GJ in 2012 and reflects the cost of gas embedded in this RRA, Moderate scenario has an approximate weighted average cost of gas of $6.91/GJ in 2012 and the High scenario has an approximate weighted average cost of gas of $8.61/GJ.

Figure 1.2-2: Significant FEVI Rate Increases are Expected with the Loss of Royalty Revenues and in the Absence of Amalgamation[17]



Assuming no rate mechanisms are in place (e.g., no use of RSDA to offset Royalty Revenue loss), increases of this magnitude over the next four years may impact FEVI's ability to increase its customer base and retain existing customers. FEVI has long recognized that a lasting solution is required, and FEU believes that amalgamation and rate harmonization is that solution.

AMALGAMATION AND HARMONIZED RATES REPRESENTS LASTING SOLUTION

In the pending Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011, FEU will make the case that amalgamation of FEVI with the other FEU companies, coupled with rate harmonization / postage stamp rates for the amalgamated entity, is the lasting solution to mitigate the projected rate increases anticipated due to the cessation of the Royalty Revenues paid to FEVI. A brief overview of that rationale is provided below for context only.

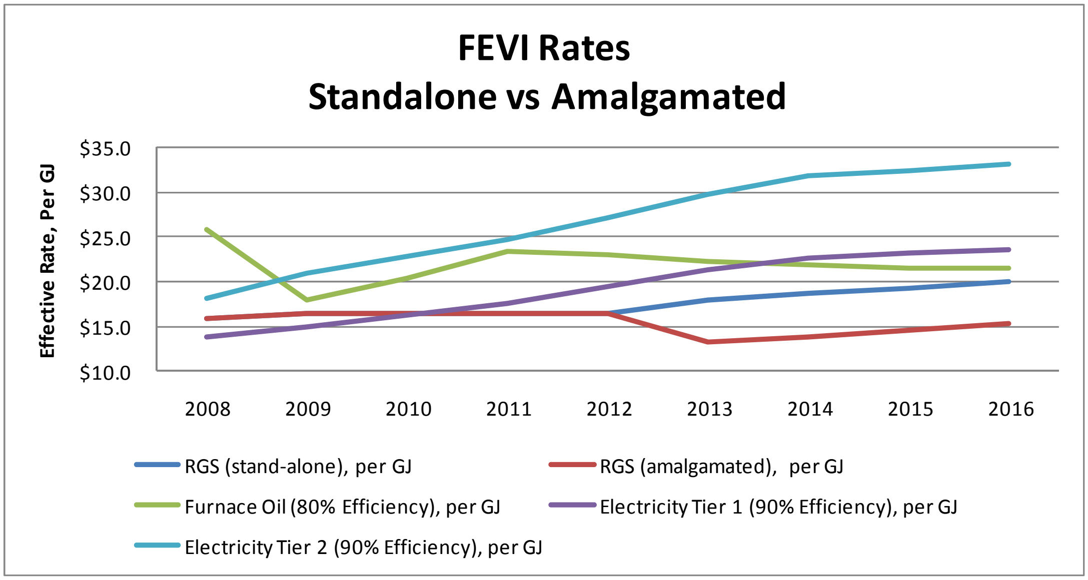
The basic reason why amalgamation and rate harmonization represents a lasting solution is that combining the FEVI rate base and customers with the other utilities in 2013, which will be the result of rate harmonization for the amalgamated utility, results in FEVI's higher fixed costs being spread over a larger customer base. FEVI's approximately $138 million in delivery costs[18], based on approximately $814 million of fixed assets[19], would be spread over approximately 1 million customers (i.e., the combined customer base of all three utilities) versus 100,000 customers. Further, FEVI's forecast $40 million increase in cost of service, as a result of the loss of Royalty Revenues, spread over approximately 1 million customers has less of an effect

17 This analysis excludes the impact of the allocation of the RSDA balance.
18 Section 7.2, Schedule 6
19 ibid

on rates than the same $40 million revenue shortfall spread over approximately the 100,000 customers of FEVI.

Figure 1.2-3 below displays the change in competitiveness expected in FEVI's service area if amalgamation is approved.

Figure 1.2-3: FEVI's Rates are More Competitive in an Amalgamated Entity than Standalone



Based on these figures it is evident that FEVI will be more competitive under an amalgamated scenario than left as a standalone utility.

Similarly, FEW customers would also benefit from moving into an amalgamated entity. FEW in many regards has similar challenges as FEVI with respect to remaining competitive from a 'price point' perspective vis-a-vis alternative energy options, e.g., electricity. FEW also has a small customer base over which to recover the costs of maintaining natural gas service. Therefore, it is also true in the case of FEW that combining the FEW rate base and customers with the other utilities will enable it to spread its cost structure over a larger customer base, thereby, mitigating against future potential rate increases. Indeed, it is expected that FEW customers will benefit through reduced rates upon Amalgamation. For example, a Residential FEW customer is expected to see an annual bill decrease of approximately 30-40 percent upon amalgamation.

FEU believe that enabling FEVI and FEW to remain competitive within an amalgamated entity can be achieved with impacts of approximately 9 percent to FEI's delivery rates, approximately $70 per year or 4 percent to the annual bill of a Lower Mainland Residential customer. FEI will make the case in the Fall Amalgamation and Phase "A" Rate Design Application that an increase in FEI rates to achieve harmonized rates is just and reasonable in light of the benefits that flow from adopting a rate structure where all customers in the combined FEU service territories have access to harmonized rates and services.

SUMMARY

In summary, the FEU's current rate structure is a result of FEU's growth via acquisition. The three service regions (FEI, FEVI and FEW) each retain the historic regulatory structures set by the predecessor company. FEU believes that bringing the gas utilities together as one company and adopting harmonized rate structures across all of the present service areas makes good sense for all of our customers and the communities we serve. By forming a single company with postage stamp rates, all natural gas customers will have access to affordable natural gas service.

1.2.5.2 Approval of Consolidated Cost of Service Is A Necessary First Step

A first step towards postage stamp rates for 2013 is to obtain Commission approval of an amalgamated cost of service, reflecting the combined costs of the three entities. The FEU believe, for the reasons set out below, that obtaining approval of an amalgamated cost of service as part of the present Application (rather than doing it as part of the Fall 2011 Amalgamation and Phase 'A' Rate Design Application) is most efficient:

- The approved consolidated cost of service will provide the platform for performing the cost of service analysis ("COSA") that will support a postage stamp rate design.
- There will be overlap in cost of service issues relating to the utility-specific and amalgamated views. For example, any items raised with respect to an individual entity's cost of service will flow through to the amalgamated cost of service; therefore, addressing these items in one application makes sense as opposed to having a 'secondary' review of the cost of service in the context of a future application that may lead to duplication of issues raised and addressed in this Application.
- The cost of service issues are conceptually distinct from the rate design issues that are to be the focus of the Fall 2011 Amalgamation and Phase 'A' Rate Design Application.
- The FEU believe that the Commission can make a determination on the amalgamated cost of service without prejudging the merits of amalgamation that will be addressed in the subsequent Amalgamation and Rate Design Phase 'A' application. The wording of the order sought, as set out in Section 8, reflects a conditional approval of the amalgamated cost of service "subject to" the subsequent approval of amalgamation and approval of harmonized rates. The rate design-related orders from the Phase "A" rate design will yield the harmonized 2013 rates.

For these reasons, the FEU believe that the review of the amalgamated cost of service is best undertaken in this Application. All issues relating to the merits of amalgamation, the rationale for moving to postage stamp rates, or the design of postage stamp rate structures should be deferred to the Fall 2011 Amalgamation and Rate Design Phase 'A' Application.

1.2.5.3 Two-Phase Process to Achieve Postage Stamp Rates

As mentioned above, it is the FEU's intention to file two further applications after the present Application, the first of which is the Amalgamation and Phase 'A' Rate Design Application slated to be filed this Fall for rates effective January 1, 2013. It will establish permanent harmonized rates for 2013 for the amalgamated entity. The second application (Rate Design Phase 'B' Application) will be filed following a decision on the Fall 2011 Phase 'A' Application. The Phase "B" Application will involve further Rate Design for the amalgamated entity effective for 2014. FEU describes below, at a high level, its expectation about what these two applications will entail.

FEU AMALGAMATION AND RATE DESIGN PHASE 'A' APPLICATION

The Amalgamation and Rate Design Phase "A" Application will seek approval under Section 53 of the UCA to amalgamate FEI, FEVI and FEW effective January 1, 2013. Under section 53, amalgamation requires the consent of the Lieutenant Governor in Council ("LGIC"). FEU will request in the application that the Commission submit a report to the LGIC finding that amalgamation would be beneficial in the public interest, as contemplated in the UCA.

The purpose of seeking amalgamation is to facilitate the implementation of postage stamp rate design for the combined service area, and FEU would not incur the cost to amalgamate in the absence of postage stamp rates. Thus, in a mutually dependent approval, FEU will seek as part of the application to move to a harmonized rate structure across its entire service area. In this initial phase, the combined entity will adopt the rate classes and structures of FEI. The outcome of the rate design will be a request for approval of 2013 permanent rates for the amalgamated entity, effective January 1, 2013.

RATE DESIGN PHASE 'B' APPLICATION FOR 2014

The Rate Design Phase "B" Application will build upon the prior application by considering further rate design items such as rate structure, changes to rate schedules and their terms and conditions and, if required, further rate rebalancing.

FEU anticipate filing this application in either the second or third quarter of 2012, dependent upon the timing of a decision on the Phase "A" application. If approved, the outcome of the rate design will be effective January 1, 2014.

1.2.5.4 Summary of Amalgamation and Harmonized Rate Structure

In light of the benefits that the FEU see with pursuing amalgamation and postage stamp rates across the combined service areas of the FEU, and our intention to apply for both later this year, we have sought a determination of the amalgamated cost of service as part of this RRA. FEU believe that it is most efficient to address the cost of service related issues at this time, rather than leaving them to be addressed in the Amalgamation and Rate Design Phase 'A' Application. The Commission can, and we respectfully submit should, determine the amalgamated cost of service without prejudging the benefits of amalgamation and postage stamp rates. The approval sought in respect of the amalgamated cost of service has been framed to make it clear that these issues remain to be determined in a future process.

1.3 Conclusion of Executive Summary and Introduction

In this RRA, the Utilities have included the costs and strategies to successfully deliver on existing commitments, with an increased focus on the safety and reliability of our system, and another step towards delivering a long term rate mitigation strategy for Vancouver Island and Whistler. If approved as forecast, the revenue requirements for 2012 and 2013 will set the stage for the future, enabling both customers and the Utilities to have a sustainable business model and more equitable rates across the service territories served by the FEU.

2 ORGANIZATION OF THE APPLICATION

This RRA is the first that has presented the revenue requirements for each of the four utilities in one comprehensive application, showing both individual utility costs and, wherever possible, an amalgamated view. The Application has been organized in this fashion to assist interested parties in gaining an understanding of differences and similarities between each of the utilities, and providing a high level view of the future under an amalgamated utility.

The sections of this Application are organized as follows:

1. Introduction and Executive Summary
2. Organization of the Application – current section
3. Revenue Requirements and Rates – An overview of the process and accounting policies used to determine revenue requirements, a summary of revenue requirements, and a summary of rate proposals.
4. Demand Forecast and Revenue at Existing Rates – A review of the forecasting methodology, the use rates and customer additions by utility and rate class, and the total demand and revenue forecast for each utility.
5. Cost of Service

    5.1 Introduction – An overview of the components of cost of service.

    5.2 Cost of Gas – A review of the cost of gas included in the cost of service forecasts.

    5.3 Operations and Maintenance ("O&M") Expense – A discussion of cost drivers for changes in O&M and full-time equivalent employees, followed by a department by department review of the gross O&M for 2010 through 2012, and a discussion of capitalized overheads and corporate and shared services.

    5.4 Depreciation and Amortization – A summary of the results of the recent depreciation study, the proposed treatment for negative salvage, and a review of the accumulated losses in FEI.

    5.5 Other Revenue – A summary of other revenue by utility.

    5.6 Taxes – A discussion of income taxes, property taxes, and other taxes and tax issues.

    5.7 Financing Costs and Return on Equity – Cost of debt and cost of equity calculations.

6. Rate Base – A summary of rate base for each utility, capital expenditures and rate base deferral accounts, and working capital.

7. Financial Schedules – Financial schedules for each utility.

8. Approvals Sought and Proposed Regulatory Process – A list of the various approvals sought, and the proposed regulatory process.

The following Appendices are included as part of the Application:

A. Glossary of Terms – Definitions of terms used throughout the Application.

B. Company and Regulatory Information – History of companies, legal and regulatory, discussion of the various service areas, and referenced previous decisions and concordance with directions.

C. Forecasting Data – Forecast assumptions, sources of Consumer Price Index information, sources of interest rate forecasts, and historical customer additions, use rates, weather, housing starts and energy demand.

D. Historic Data – Summary tables of Operating and Maintenance expense, FTEs, Utility Income and Earned Return, Income taxes, Return on Capital, Utility Rate Base, Capital Expenditure, and Customer Service Call Volume from 2006 onwards.

E. Depreciation – Gannett Fleming depreciation study, report on asset removal costs and asset retirement obligations, report on accumulated losses in FEI.

F. Tariffs – includes Tariff Continuity and Bill Impact Schedules for each utility as well as a discussion of the changes to the lock off and reconnection fees.

G. Non Rate Base Deferral Accounts – summary of non rate base deferral accounts by utility, including Thermal Energy Services (formerly Alternative Energy Services).

H. Organization Charts – Organization charts showing number of employees by department and reporting relationships.

I. Compressed Natural Gas and Liquefied Natural Gas Fueling Report

J. Biomethane Report

K. Energy Efficiency and Conservation Report

L. Financial Matters

M. Draft Form of Order

3 REVENUE REQUIREMENTS AND RATES

This section discusses:

1. How the Companies' management structure, compensation philosophy and O&M and capital budgeting and control processes contribute to effective management of the costs that are incorporated into these revenue requirements;
2. What accounting policies have been utilized in calculating the revenue requirements, and how the pending US GAAP Decision may impact the costs included in these revenue requirements;
3. The revenue requirements by utility and of the cost of service on an amalgamated basis, summarizing the forecasts included in Sections 4 through 6, and the financial schedules in Section 7; and
4. Rate proposals for each utility.

3.1 Management of Costs and Rate Determination

The FortisBC Energy Utilities remain focused and committed to providing cost-effective, high-quality service to our customers, while ensuring employee and public safety, and operating in an environmentally responsible manner. In advancing these objectives, the FEU employs an appropriate management structure, a variety of metrics to assess corporate performance, and a compensation program that is tied to the achievement of objectives. Each of these elements is discussed below.

3.1.1 MANAGEMENT STRUCTURE

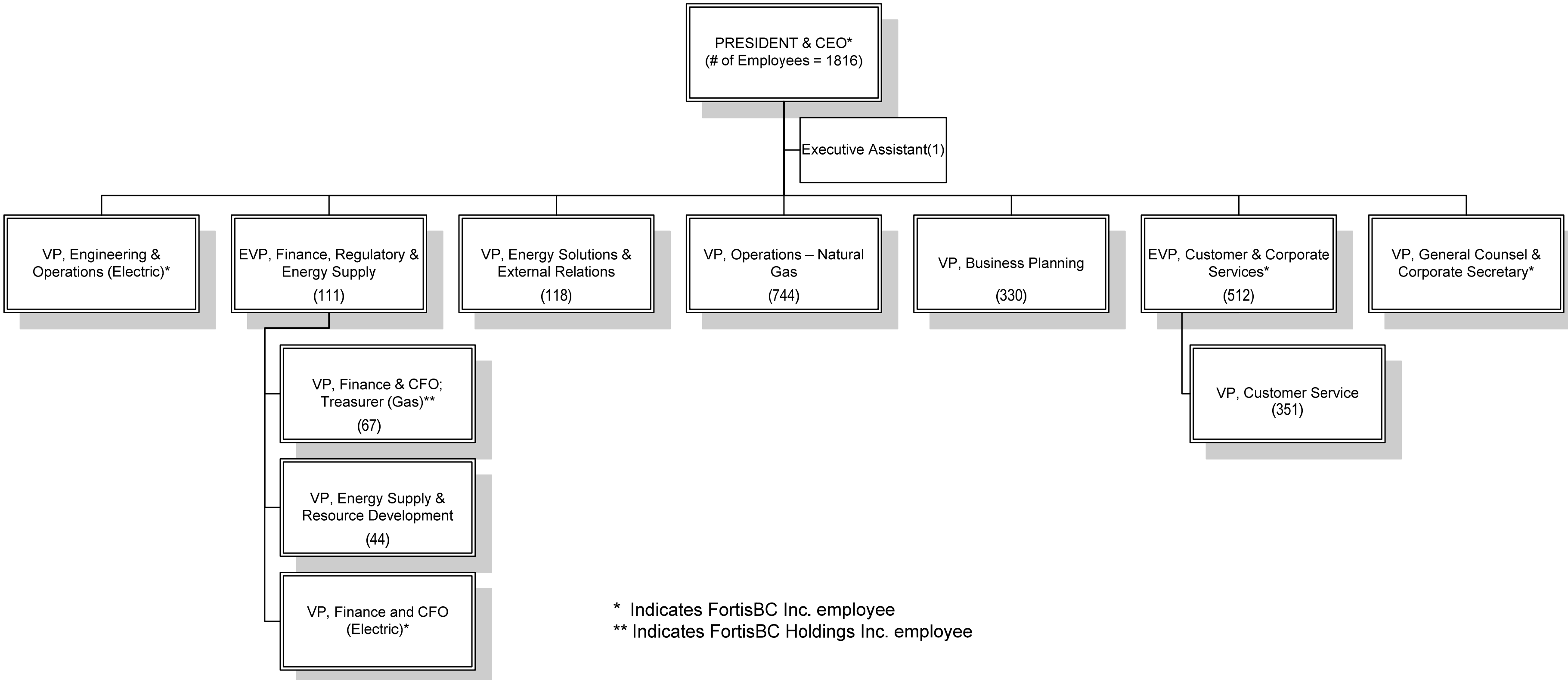
The Companies' ability to deliver on their commitment to customers to provide safe and reliable service in a cost effective manner is dependent on their management team and management structure. Below, the FEU describes the evolution of the management team and structure in response to changes in business requirements.

The Executive Leadership Team ("ELT"), comprised of the President and Vice Presidents, is responsible for providing overall leadership and strategic guidance. The ELT provides the strategic direction for the Companies and develops the business plan in support, including the setting of the performance targets. The ELT works closely with the Utilities Operating Committee ("UOC") to ensure that business goals and objectives are achieved, advancing the needs of customers, employees and the shareholder. The UOC is comprised of senior managers representing the different departments within the Companies and operates under the guidance of ELT. The UOC's mandate is to deliver on the targets as laid out in the Scorecard (discussed in the next section) while maintaining the Company's focus on providing safe, reliable and cost effective service.

In March 2010, Fortis Inc. announced a combined leadership structure for its two BC operations, FortisBC Inc. and the FortisBC Energy Utilities. The move to a common name and identity builds on a common leadership structure by aligning resources under one name and providing customers with one face through which to know the various energy offerings of Fortis including natural gas, electricity, and thermal energy. Although the names of the Terasen utilities changed to FortisBC, they will continue to operate as separate legal entities. It will be primarily business as usual. However, the move to a combined leadership structure is evident in the organizational structure of FEU at the leadership level. To varying degrees the leadership positions are shared between the FEU and the FortisBC electric utility, in which case employees of one entity will cross charge an appropriate share of their time to the other entity to achieve an appropriate allocation of cost. There are also leadership positions in FortisBC Holdings Inc., the parent company, in which case a share of their time is charged to the FEU through the corporate services fee. Details on the corporate services fee as well as shared services are addressed in Section 5.3.18.

Figure 3.1-1 below shows the organizational structure of FEU at the leadership level. Similar organizational charts, each portraying a forecast view as at December 31, 2011, are provided for each business area in the O&M 5ection 5.3 and typically drill down to a senior manager level. Each organizational chart will indicate the employees forecast as at December 31, 2011.

Figure 3.1-1: Organization Chart for Leadership Team



* Indicates FortisBC Inc. employee
** Indicates FortisBC Holdings Inc. employee

3.1.2 ORGANIZATION PERFORMANCE

The FortisBC Energy Utilities use a Balanced Scorecard approach to deliver on a number of key success measures critical to the business. This performance assessment is key for management in evaluating past performance and in determining the most cost effective service level for customers going forward.

FEU's Scorecard is comprised of four categories of measures with 10 measures in total that describe and guide the Companies' overall performance in meeting the targets that are set annually. The Scorecard serves as a valuable communication tool used to describe in clear and objective terms success measures for the FortisBC Energy Utilities. The four categories of measures include Financial, Customer, Key Processes and Employee and are described below.

FINANCIAL

Net earnings for FEU is used as the financial performance measure taking into account earnings from revenues, operating and maintenance expenses, depreciation, amortization, property taxes, interest expense and income taxes. It incorporates the approved costs and revenues that are utilized in determining customers' rates each year.

CUSTOMER

The three measures related to the category Customer include O&M per customer, Base Capital and Customer Satisfaction. The O&M and Base Capital amounts included in the Scorecard targets are the same O&M and Base Capital amounts that are incorporated into the determination of customers' rates. Effective management of costs is an important Scorecard measure. This includes managing O&M on a per customer basis and total capital expenditures (excluding CPCN projects). Success in meeting customer expectations is measured through the use of an index score calculated with information collected through surveys of customers' opinions, and includes residential, commercial, and builder/developer customer groups. Billing, corporate image and marketing communications are tracked as they are the three most important customer satisfaction drivers for residential customers.

KEY PROCESSES

Key processes consist of business processes that support Credit and Collections and control of bad debts and Execution against Regulatory Priorities. Credit and Collections is measured by FEU's ability to manage its residential and commercial customers' bad debt experience. Execution against Regulatory Priorities highlights the importance of achieving success on regulatory issues and agreements for the benefit of customers and the shareholder.

EMPLOYEE

Employee and public safety is fundamental. The Employee measure encompasses four components including Recordable Vehicle Accidents, Recordable Injuries, Wellness and Public Safety. Scorecard targets for vehicle accidents and employee injuries are set to encourage employee behaviours that all accidents are preventable and no accidents are acceptable. Wellness is measured as a composite of annual days lost per employee and is intended to promote attendance at work for employees. Achievement in Public Safety is measured by consideration of safety metrics in the utilities' service quality indicators.

FEU believe that the Scorecard is an effective tool for improving organizational alignment and helping to focus the Companies' activities on key measures. In the future, the Scorecard will remain an essential tool to measure the Companies' performance on key success measures important to customers, the regulator, and the shareholder.

SERVICE QUALITY INDICATORS (SQI'S)

For 2012 -2013 the FortisBC Energy Utilities will continue to report on Service Quality Indicators set out in the FEI 2010-2011 RRA Negotiated Settlement Agreement (Item 6). We will be reviewing these Service Quality Indicators when the CCE Project is fully implemented, and FEU will have greater control of the information and data in this area. The FEU are committed to enhancing the level of customer satisfaction and also meeting emerging challenges of the energy market into the future. To this end we feel the current SQI's and Scorecard help to measure our commitment to these goals.

FEU reports on SQIs that are comparable to the energy industry best practices and posts them quarterly on the website. The 10 Service Quality Indicators that the Companies measure and compare against on an annual basis are presented in Table 3.1-2.

Table 3.1-2: Service Quality Indicators

Customer Performance Indicator	Benchmark	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual
Emergency Response Time – Time Dispatched to Site - Emergency – flowing Gas	≤21.1	22.00 minutes	21.36 minutes	21.42 minutes	21.30 minutes	20.36 minutes	20.42 minutes	22.41 minutes	22.30 minutes
Speed of Answer – Emergency (% of calls answered within 30 sec.)	≥95.0%	96.3%	97.9%	98.8%	98.6%	98.4%	98.3%	98.3%	99.2%
Speed of Answer – Non-Emergency (% of calls answered within 30 sec.)	≥75. 0%	76.4%	77.5%	76.9%	78.2%	76.9	73.8%	76.7%	77.2%
Transmission Reportable Incidents	≤2	3	3	3	1	1	2	0	0
Index of Customer Bills Not Meeting Criteria	≤5	2.63	1.93	1.97	0.77	2.30	7.53	3.75	2.40
Percent of Transportation Customer Bills Accurate	≥99.5%	99.8%	96.6%	99.9%	99.9%	99.5%	94.3%	96%	99.9%
Meter Exchange Appointment Activity	≥92.2%	92.6%	93.5%	94.3%	94.1%	93.5%	94.5%	94.7%	94.2%
Accuracy of Transportation Meter Measurement First Report	≥90.0%	97.4%	98.0%	99.5%	98.1%	98.9%	96.2%	98.7%	97.6%
Independent Customer Satisfaction Survey	Compared to prior years	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	80.1%	80.%
Number of Customer Complaints to BCUC	Compared to prior years	101	191	121	152	130	90	58	26
Number of Prior Period Adjustments	Compared to prior years	24	18	14	21	23	15	21	14
Directional indicators									
Leaks per Kilometer of Distribution System Mains	N/A	0.0040 134	0.0045 150	0.0034 120	0.0021 76	0.0024 87	0.0016 57	0.0031 60	0.0073 140
Number of Third Party Distribution System Incidents	N/A	1,459	1,492	1,457	1,508	1,545	1,574	1,322	1,246

FEU will continue measuring its operational performance using best practice Service Quality Indicators as we have done in the past.

3.1.3 COMPENSATION MANAGEMENT

For the purposes of compensation and benefits, our workforce is separated into three primary groups:

- Executives;
- M&E employees; and
- Unionized employees represented by the IBEW and COPE unions.

While the details of the compensation and benefits programs vary between these three groups, the Company applies the same philosophy and approach to compensation and benefits for all employees. This approach includes a total compensation package that rewards employees with competitive base salaries and wages, incentive compensation, benefits, and paid time-off. Below, the FEU set out the key objectives of the compensation and benefits program, and provide further information about each of the three employee groups. A well defined compensation management structure allows us to balance being able to attract and retain talented people for key positions, while effectively managing the labour and benefit costs that are included in this RRA.

KEY OBJECTIVES

The key objectives of the compensation and benefits program are to:

- Retain and motivate a qualified, diverse workforce by recognizing and rewarding achievement, contribution, and excellence;
- Attract a qualified, diverse workforce through a competitive compensation program;
- Reward by providing a consistently applied compensation program that meets the needs of a diverse workforce; and
- Promote continuous learning, leadership development and training while understanding that it is the responsibility of each employee to manage their own growth through development planning.

In order to achieve these objectives and to ensure the sustainability of employee benefit programs, FEU and their employees have adopted cost-shared pension and benefit arrangements. In addition, through ongoing review of our plans, we incorporate industry-determined best practices such as flexible work schedules and benefits, which enable employees to personalize the benefit plan to their own needs.

EXECUTIVE EMPLOYEES

The Company's executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance. The compensation package is designed to retain and attract qualified and experienced executives as well as align the compensation level of each executive to that executive's level of responsibility. The objectives of base salary are to recognize market pay, and acknowledge competencies and skills of individuals. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance objectives and focus on key activities and achievements critical to the ongoing success of FEI. Long-term incentive plans focus executives on sustained shareholder value creation.

The Company's executive compensation program involves four main elements (base pay, short term and long term incentive pay and benefits), which comprise a Total Rewards package. All of these factors support the needs of the business and its customers, and each element contributes to finding the balance on delivering successfully on both short and longer term objectives.

As a general policy, FEU establish base and incentive compensation targets so as to compensate executives at a level generally equivalent to the median level of a broad reference group of approximately 200 Canadian commercial industrial companies.

With the exception of the pension plan, benefits provided to the executives are based on the benefit program for M&E employees. Prior to June 1, 2007, all executives participated in the pension plan for M&E employees, in either a defined benefit or a defined contribution program. Effective June 1 2007, all executives became members of a Group Registered Retirement Savings Plan ("RRSP"). The RRSP arrangement provides for equal contributions of 6 ½ per cent of salary by both the employee and employer up to the Canada Revenue Agency ("CRA") RRSP maximum limit. The Company makes notional contributions in excess of the RRSP maximum limit equal to 13 per cent of salary to a Supplemental Executive Retirement Plan ("SERP").

M&E EMPLOYEES

As a general policy, FEU establishes base and incentive compensation targets at a level approximately equal to the median level of a peer group of companies contained in the Hay Group's Paynet Database. The peer group is heavily influenced by the commercial/industrial subset with an emphasis on natural resources and utilities. By policy, the market rates are set to the 50th percentile of the peer group.

Pay increases and incentive opportunities for all employees are linked to individual and company performance which provides employees with an opportunity to increase their total compensation. Other factors, such as competitive market factors, current position in the salary range and budget guidelines may impact base pay.

FEU also offers an employee benefits program for M&E employees comprising pensions, health and welfare benefits, other work-related benefits and post-retirement benefits other than pensions. The employee benefits program is targeted to be competitive at the median level of an established group of comparator companies.

A key objective of FEU has been to provide a common benefits platform for all M&E employees. This strategy was adopted for several reasons, including simplified administration which reduces expenses and eases internal transfers. In addition, the rising cost of pensions and health care and other benefits is a concern for all Canadian businesses. We need to balance the needs of the business with those of our employees. Both are best served by a pension and benefits package that is sustainable in the future through employer and employee cost sharing, and which provides our employees with the flexibility to tailor benefits to meet their needs. The provision of a flexible benefits plan generates a greater understanding of the benefits available to the employee and the associated costs, and promotes prudent consumerism.

UNIONIZED EMPLOYEES

In 2006 and 2007, Terasen Gas reached five-year labour agreements with the IBEW and COPE respectively. These agreements introduced significantly greater flexibility in work management, and in implementing common flexible benefits and post-retirement benefits plans.

All IBEW and COPE employees belong to the FEI Pension Plan for IBEW and COPE Members. This plan is a jointly trusted and cost-shared defined benefit pension plan. As with M&E employees, FEU has made considerable progress in negotiating harmonized benefit plans for active and retired IBEW and COPE employees.

The labour and benefit inflation rates that are included in this RRA and that result from the compensation management structure outlined above are included in Section 5.3.2.2 of this Application.

3.1.4 CAPITAL AND OPERATING AND MAINTENANCE FORECASTING PROCESSES TO DETERMINE REVENUE REQUIREMENTS

The capital and O&M forecasts included in this Application result from adhering to the capital and O&M forecasting processes described below.

3.1.4.1 Capital Spending

Over the next five years, the FortisBC Energy Utilities expect to spend approximately $1 billion in Regular Capital expenditures to meet customers' needs and to maintain the integrity and reliability of the gas facilities. As in the past, the Companies manage the capital expenditures using defined capital approval policies and management processes. Capital funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that capital is put to its best use while minimizing the impact on customers' rates.

The FEU Capital Approval policy outlines an approval process with responsibilities and approval limits defined to ensure appropriate capital spending decisions are made. Annual capital budgets are reviewed and approved by the ELT and UOC. Subsequently, before capital spending occurs in the year, capital projects are reviewed to ensure appropriateness of budget estimates, priority and availability of staffing and resources to implement.

For information technology related projects, to ensure the effectiveness of prioritization of funding, all projects regardless of dollar value require review and approval by the UOC.

Customer driven capital consisting of new mains, meters and services are governed by the System Extension and Customer Connection polices which were approved by the Commission in Order No. G-152-07 in December 2007.

For large capital projects subject to CPCN requirements, senior management reviews the projects and obtains Board of Directors approval where necessary prior to filing the CPCN applications with the Commission.

The FEU believe that the forecast capital expenditures for 2012 and 2013 reflects the discipline imposed by these management structures. For a further description of the capital expenditure process, please see Section 6.2 Capital Expenditures.

3.1.4.2 Operating and Maintenance Spending

Similar to the management of capital spending, FEU manages its greater than $200 million of annual O&M expenditures using its defined approval policies and management processes. These policies and management processes are in place to ensure that O&M forecasts have been developed in support of the Companies' business priorities and objectives, ensuring that O&M funding is appropriate and prioritized to meet the current and longer-term needs of customers.

O&M budgets are developed annually by the UOC and reviewed and approved by the ELT. Existing department O&M budgets are reviewed to ensure their appropriateness and continued justification. Incremental O&M funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that funding is put to its best use while minimizing the impact on customers' rates. This holistic approach to O&M budgeting is more suited to achieving an optimal allocation of resources to realize the Companies' goals and objectives than that by following an exclusively incremental focus or being driven exclusively from the top down.

Monitoring and management of actual O&M expenditures during the year is primarily the responsibility of the UOC. The UOC tracks spending against budget targets. In addition, where the opportunity permits, available funding is reprioritized and allocated to fund more pressing or beneficial initiatives that arise. Through this regular review process, the Company is able to ensure O&M funds are put to their best use by responding to changing circumstances as appropriate. The FEU believe that the forecasted O&M for 2012 and 2013 reflects the discipline imposed by this management and monitoring framework.

3.2 Generally Accepted Accounting Principles ("GAAP") Used in Determining Revenue Requirements

This Application has been prepared using accounting policies and estimates assuming the continuation of the IFRS compliant policies that were approved in the setting of rates for 2011 for the Utilities. The accounting policy changes approved at that time are still allowed under IFRS, and are also allowed under US GAAP, except as noted below.

On February 9, 2011, the Fortis BC Utilities (FortisBC Inc. and the FEU) filed an application requesting approval for the use of US GAAP (the "US GAAP Application") in the determination of rates as of January 1, 2012. Specifically, the application sought approval for:

1. The use of US GAAP for the calculation of cost of service, revenue requirements, rate base, and the preparation of regulatory schedules and filings effective January 1, 2012; and
2. Recording the one-time conversion costs associated with the adoption of US GAAP in a rate base deferral account for each of the Companies, for recovery from its respective customers in 2012 and 2013.

The FEU filed the application for the adoption of US GAAP once it became apparent that IFRS would not allow the recognition of rate regulated assets and liabilities for external financial reporting. The Companies believe continued recognition of regulatory assets and liabilities best reflects the effect that regulatory activities have on the Companies' financial position and the economic realities of their businesses and the regulatory model they operate under. The only set of accounting standards that currently exists that would allow for regulatory assets and liabilities to continue to be recognized is US GAAP; therefore, US GAAP is the reasonable and prudent accounting standard for the Companies to report under.

The following two sections deal with the impacts on revenue requirements of either fully implementing IFRS but with deferral accounts, or adopting US GAAP. In addition, the FEU have included a summary of the current reconciling items between regulatory reporting and external financial statements as Appendix L-1, to provide some background around the level of reconciliation that is currently required.

3.2.1 IFRS WITH DEFERRAL ACCOUNTS FOR RATE SETTING PURPOSES

If the FEU continued with the adoption of IFRS for both rate setting purposes and external financial reporting, there would be many reconciling items between external financial reporting and regulatory reporting. This is because regulatory assets and liabilities would not be recognized for external financial reporting, creating a significant increase in the reconciliation process between regulatory reporting and financial reporting. Over the course of a number of years, this reconciliation would get more complicated as certain deferrals are recovered from customers while others would continue to build through time.

3.2.1.1 Changes to Fully Implement IFRS

Even under a scenario where IFRS with deferral accounts is adopted for rate setting purposes only, changes would be required to the current accounting treatment included in this RRA. On the adoption of IFRS, all regulated assets and liabilities would need to be de-recognized for external financial reporting as IFRS does not recognize the effect of rate regulated accounting. Once adopted, any impacts of rate regulation that are included or embedded in other assets or liabilities could not be recognized on a go forward basis. A key area of difference is the treatment of Pension and Other Pension and Employment Benefits, which is discussed in Section 3.2.1.2. The other areas where this is expected to impact the current RRA include:

1. The rate of overheads capitalized that would be allowed to be included in property plant and equipment would be limited to the rate that would be considered "directly attributable". The overheads study filed in conjunction with the 2010/2011 RRAs indicated that the rate would have been 8 percent for FEI and 5 percent for FEVI. The difference between this rate and the 14 percent overheads capitalized rate agreed to as part of the NSA would be captured in a deferral account for regulatory purposes rather than as part of property plant and equipment.
2. FEU would be unable to recognize AFUDC under IFRS. Similar to the treatment of overheads capitalized rate differences, differences between the AFUDC rate and an allowed interest during construction rate would need to be captured in a deferral account rather than as part of property plant and equipment.
3. On the adoption of IFRS, accumulated depreciation and amortization is required to be netted against the cost to effectively reset the cost of capital and intangible assets on transition. This re-setting would not be expected to affect the depreciation expense included in the revenue requirements calculation in this Application although the presentation of assets and depreciation rates would be impacted.

3.2.1.2 Pension and Other Post Employment Benefits

Consistent with the treatment included in this Application, on the adoption of IFRS, all unamortized pension actuarial gains and losses, past service cost and transitional obligations would require recognition as an opening adjustment to retained earnings for external financial reporting. For regulatory reporting purposes, these amounts have been captured in the IFRS Transitional Deferral account that was requested in the 2010/2011 RRA for FEI and FEVI. In the current application, FEI and FEVI have proposed to recover these amounts over the Expected Average Service Life ("EARSL") for each benefit plan. Additionally, the current method of recognizing actuarial gains and losses through pension expense is being re-examined by the IASB. If the current policy on the corridor method is removed from IFRS, the FEU may be required to recognize the effect of actuarial gains and losses in the current period rather than deferring the effects by the use of the corridor method.

3.2.1.3 Costs associated with the adoption of IFRS

In our US GAAP Application, the FEU outlined the expected costs of adopting both IFRS and US GAAP. The costs included in that GAAP Application include an increase in the one-time costs associated with adopting IFRS and an increase in the on-going costs of IFRS. Both types of costs have increased due to the fact that the effects of rate regulation would not be recognized in the external financial statements of the FEU. The FEU had estimated the incremental one-time costs at $1.4 million and incremental on-going costs at $0.9 million. These costs have not been included in this application as the Companies do not expect they will adopt IFRS for external financial reporting purposes.

3.2.2 ADOPTION OF US GAAP FOR RATE SETTING PURPOSES

The adoption of US GAAP for rate setting purposes has fewer adjustments than adopting IFRS and is closer to the existing reporting under Canadian GAAP. The FEU have committed to adopting US GAAP for external financial reporting and have also requested the adoption of US GAAP for rate setting purposes.

The following is a discussion of the differences between US GAAP and our existing regulatory policies and treatments that affect cost of service and rate base that have been identified to date.

3.2.2.1 Pension and Other Post Employment Benefits

ADOPTION DATE OF PENSION ACCOUNTING FOR US GAAP AND TRANSITIONAL OBLIGATION/BENEFIT

The Canadian Institute of Chartered Accountants adopted accrual accounting for pension and other post employment benefits ("OPEB") starting January 1, 2000. As a result of the adoption of accrual accounting, a transitional benefit/obligation was created which has been amortized to pension expense over the Expected Average Service Life ("EARSL"). The equivalent standard under US GAAP is FASB Statement 87 (FAS 87) which came into effect on January 1, 1989.

It would be virtually impossible for the FEU to obtain actuarial data prior to 2000 and as such, there is an accommodation available to foreign registrants who are adopting US GAAP. The accommodation essentially allows for the calculations of net benefit expense for pension and OPEBs to be calculated from 2000 onwards except for the transitional obligation/benefit created on adoption of Canadian GAAP. The transitional obligation that was created in 2000 when

Canadian GAAP adopted accrual accounting for pension benefit plans is moved back to 1989 and assumed to be amortized from the period onwards. Any transitional obligation remaining would be recognized in a deferral account.

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a rate base deferral account to capture any unamortized transitional benefit/obligation on the adoption of US GAAP (similar to the IFRS Transitional Deferral account). Under Canadian GAAP, these amounts are effectively part of the pension asset/liability which forms part of rate base today.

This is not expected to have a material effect on cost of service or rate base for any of the FEU. The amortization of the transitional obligation under Canadian GAAP is already included in the net benefit expense. By recognizing the transitional amounts in a rate base deferral account, the amortization could continue assuming the remaining EARSL is used.

Overall, the effect and amounts involved under the US GAAP scenario are materially lower than under transitioning to IFRS. The following table compares the projected pension and OPEB expense under existing Canadian GAAP, IFRS assuming an adoption date of January 1, 2010 and US GAAP. It also includes the effect of amortizing the regulatory asset created if the adoption of IFRS had taken place as of this date. The amortization period used is the EARSL by plan.

Table 3.2-1: Pension and OPEB Expense under US GAAP and IFRS

		2012				2013	
(in 000's)	**US GAAP**	**IFRS**	**Difference**		**US GAAP**	**IFRS**	**Difference**
FEI		**EARSL**				**EARLS**	
Legacy	1,904	(230)	2,134		1,162	(400)	1,562
Union	8,016	4,403	3,613		7,263	4,272	2,991
TI Plan	4,219	4,228	(9)		4,143	4,190	(47)
	14,139	8,401	5,738		12,568	8,062	4,506
Amortization		6,132	(6,132)			6,132	(6,132)
Net Pension	14,139	14,533	(394)		12,568	14,194	(1,626)
OPEB	4,779	4,134	645		4,917	4,367	550
Amortization		1,007	(1,007)			1,007	(1,007)
Net OPEB	4,779	5,141	(362)		4,917	5,374	(457)
Total - FEI	18,918	19,674	(756)		17,485	19,568	(2,083)
FEVI							
Legacy	1,487	846	641		1,302	767	535
TI Plan	237	232	5		237	237	-
	1,724	1,078	646		1,539	1,004	535
Amortization	-	621	(621)			621	(621)
Net Pension	1,724	1,699	25		1,539	1,625	(86)
OPEB	616	361	255		620	385	235
Amortization	-	306	(306)			306	(306)
Net OPEB	616	667	(51)		620	691	(71)
Total - FEVI	2,340	2,366	(26)		2,159	2,316	(157)

The net effect under each scenario presented above show that the effect of adopting US GAAP has a materially lower total cost compared to adopting IFRS.

RECOGNITION OF FUNDED STATUS ON THE BALANCE SHEET

US GAAP requires that the funded status of benefit plans – measured as the difference between the fair value of plan assets and the benefit obligation – be recognized on the balance sheet of the entity. For pension plans, the benefit obligation shall be the projected benefit obligation and for OPEB plans, the benefit obligation shall be the accumulated post-retirement benefit obligation. In companies not subject to rate regulation, the recognition of the funded status has a corresponding adjustment to other comprehensive income. The adjustment essentially recognizes any unamortized gains and losses due to the application of the corridor method, prior service costs (and credits), and any remaining unamortized transitional obligation/benefit. Through time, all of these components will be recognized through the net periodic benefit cost.

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a rate base deferral account to capture the difference between the carrying value otherwise determined and the funded status of the benefit plans. Similar to the transitional obligation discussed above, these amounts are effectively part of the pension asset/liability which forms part of rate base today.

This is not expected to have any effect on cost of service or rate base for any of the FEU. The recognition of the funded status is simply a re-classification between the pension/OPEB rate base amounts and a deferral account.

MEASUREMENT DATE

US GAAP, like IFRS, requires that benefit plans use a measurement date coinciding with the fiscal year end of the Company. FEI, FEVI and FEW all use a measurement date of December 31 so this is not expected to have any impact.

3.2.2.2 Uncertain Tax Positions

Financial Accounting Standards Board Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, was implemented in 2006 and was intended to reduce uncertainty in accounting for income taxes. The standard requires a series of steps for the recognition, measurement, disclosure and presentation of uncertain tax positions. The accounting and reporting requirements of FIN 48 involve a two-step process that may result in a larger income tax liability due to the earlier recognition of income tax liabilities. The standard was implemented to reduce the uncertainty and diversity in practice that the FASB had observed which resulted in non-comparability across companies. No similar standard exists under either existing Canadian GAAP or IFRS.

FIN 48 requires the FEU to have documentation and support for each adjustment made to reconcile between accounting income and taxable income. The areas of documentation have included such items as the allowance for doubtful accounts, meals and entertainment expenses, unpaid compensation, inventory obsolescence, capitalized overheads, capital additions for tax purposes, dismantling costs and deferred charges. While there are many items to document and the FEU are still at the documentation stage, we do not expect to have any material adjustments as a result of this standard. The documentation is still subject to audit and the audit may result in adjustments to positions and ultimately to the recognition of amounts under this standard.

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a non rate base deferral account to capture any differences that arise from the implementation of FIN 48.

3.2.2.3 Other US GAAP Items

A number of other adjustments are contemplated on transition to US GAAP that should not affect cost of service or rate base. These potential adjustments include the application of pushdown accounting, adjusting for how FEI accounts for Lease In/Lease Out transactions for external financial reporting, and others. None of these transactions are expected to affect regulatory accounting or reporting and would not affect the revenue requirement.

3.2.2.4 Costs Associated with the Adoption of US GAAP

In their US GAAP Application, the FEU outlined the expected costs of adopting both IFRS and US GAAP. The costs of adopting US GAAP were estimated to be incremental one-time costs of $1.8 million and incremental on-going costs of $0.9 million. These one-time costs are generally as a result of audit fees on the adoption of US GAAP. The higher on-going costs are as a result of higher audit fees including work required under Sarbanes-Oxley. These costs have not been included in this application. Under a US GAAP adoption scenario, the FEU would include the recovery of these costs through an evidentiary update to this RRA.

3.2.3 SUMMARY OF STATUS OF GAAP

In summary, upon receipt of a decision in the US GAAP Application, the FEU will provide an evidentiary update.

If the US GAAP Application is approved as proposed, the FEU will update their Application to include:

1. A total decrease in cost of service from pension and OPEBs (decrease of $782 thousand in 2012 and $2.24 million in 2013 as shown in Table 3.2-1 above) plus any associated income tax impacts;
2. The changes to rate base resulting from the pension and OPEB deferrals discussed in Section 3.2.2.1,
3. A total increase in O&M of $0.9 million in each of 2012 and 2013 for the ongoing costs of US GAAP compliance; and
4. A non rate base deferral to capture the estimated $1.8 million in one-time US GAAP conversion costs.

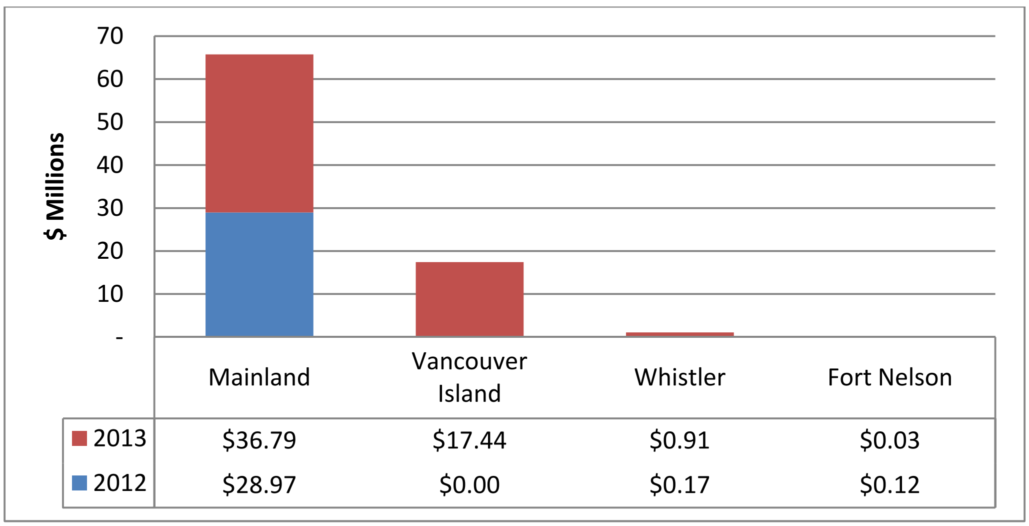
In the event that the FEU are ordered to implement accounting policies other than US GAAP, the FEU will update their Application to include the impacts of those changes.

3.3 Summary of Revenue Requirements for 2012 and 2013

The revenue requirements reflect all of the inputs in the financial schedules, and take into consideration all of the impacts described in this Application. The revenue requirement changes that the Companies are requesting are based on sound research and forecasting, using our knowledge and experience to determine what the Companies believe is the likely course of events over the upcoming forecast periods of 2012 and 2013.

The following figure provides the 2012 and 2013 revenue deficiencies for the FortisBC Energy Utilities. The revenue deficiency or surplus is determined by comparing the forecast cost of service to the forecast revenue at existing 2011 rates for each year.

Figure 3.3-1: Forecast 2012 and 2013 Revenue Deficiencies for the FortisBC Energy Utilities[20]



The revenue deficiencies result in 2012 and 2013 delivery rate changes for Mainland, Whistler and Fort Nelson as demonstrated in Table 3.3-1. The forecast revenue deficiency for Vancouver Island in 2013 is being offset by part of the projected December 31, 2012 surplus balance of $71.6 million (before tax) in the RSDA. In this Application, Vancouver Island is seeking approval for a rate freeze for 2012 (which equals the forecast cost of service) and 2013 and the continuation of the RSDA mechanism for 2012 and 2013.

20 Section 7.1 to 7.4, Schedule 2 and 3

Table 3.3-1: Revenue Deficiencies in Mainland, Whistler and Fort Nelson Result in Delivery Rate Increases[21],[22]

Utility/Region	2012	2013	Total
Mainland	5.04%	6.36%	11.40%
Whistler	2.23%	11.90%	14.12%
Fort Nelson	6.51%	1.64%	8.15%

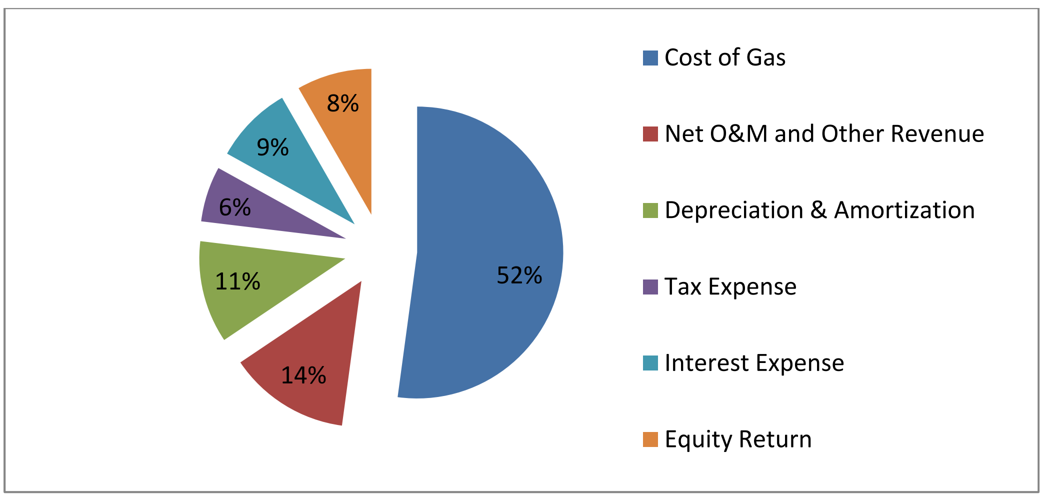
An explanation of the forecast 2012 and 2013 revenue deficiencies and rate proposals by Utility is provided in the following sections.

3.3.1 SUMMARY OF MAINLAND REVENUE REQUIREMENTS

The total revenue requirements of $1,245.1 million in 2012 and $1,282.8 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEI to continue to meet the needs of our customers and the communities in which we serve. The following sub-sections will discuss the total Mainland revenue requirement and revenue deficiencies for 2012 and for 2013.

Figure 3.3-2 provides a breakdown of the components of the Mainland total revenue requirement averaged for the two year period.

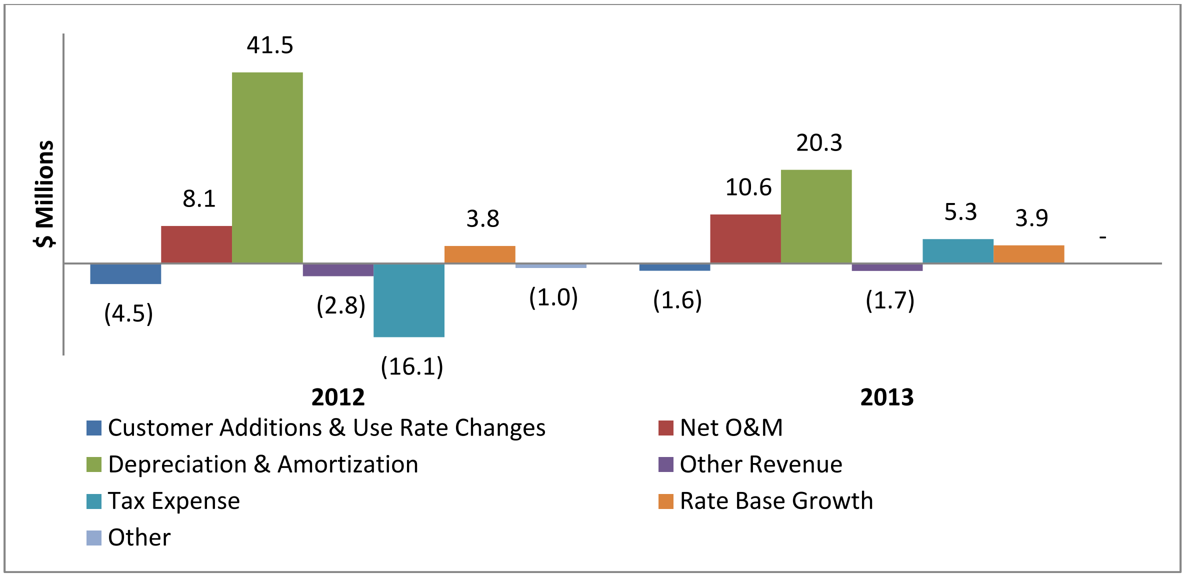
Figure 3.3-2: Average Composition of the 2012 and 2013 Mainland Revenue Requirement[23]



[21] Approximate delivery rate change percent is equal to the revenue deficiency divided by the forecast delivery margin revenue at existing 2011 delivery rates (i.e. excluding cost of gas).
[22] Section 7.1 to 7.4, Schedules 2 and 3
[23] Section 7.1, Schedule 5 and 6

Changes to the Mainland revenue requirements result in revenue deficiencies of $29.0 million in 2012 and $36.8 million in 2013. These deficiencies are summarized in Figure 3.3-3 below.

Figure 3.3-3: Mainland Revenue Deficiency Components[24]



3.3.1.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4 is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The non-bypass customer demand determined in Section 4 is 1,850 TJs greater than the demand forecast embedded in 2011 delivery rates, with a further increase of approximately 214 TJs in 2013. This increase in demand is attributable to customer growth and reflects changes in use rates and results in a revenue surplus of approximately $4.5 million in 2012 and $1.6 million in 2013. The table below shows the changes in demand by customer group for 2012 and 2013.

24 Section 7.1, Schedule 1

Table 3.3-2: Increased Demand for 2012 and 2013[25]

Non-Bypass Volume Change, TJ	Forecast 2012	Forecast 2013
Residential	1,311	(74)
Commercial	(1,864)	(61)
Other	(835)	3
Total Sales	**(1,388)**	**(131)**
Rate 22 Firm	1,318	(127)
Rate 22 Interruptible	1,147	76
Rate 23	974	334
Rate 25	(403)	57
Rate 27	211	7
Total Transportation	**3,247**	**345**
Total Non-Bypass Volume Change	**1,859**	**214**

The Demand Forecast and Revenue at Existing Rates and have been properly incorporated in the calculation of the Company's revenue requirement.

3.3.1.2 Cost of Gas

As discussed in Section 5.2, the commodity cost recovery charge and the midstream cost recovery charge for the natural gas sales rate customers are subject to quarterly review by the Commission, and Mainland is not requesting approval of forecast gas costs with this Application. Forecast gas costs are required in the determination of working capital and correspondingly rate base and earned return. The cost of gas itself does not impact the determination of the revenue deficiency or surplus because the revenue at existing rates includes commodity and midstream revenue that fully offsets the forecast cost of gas.

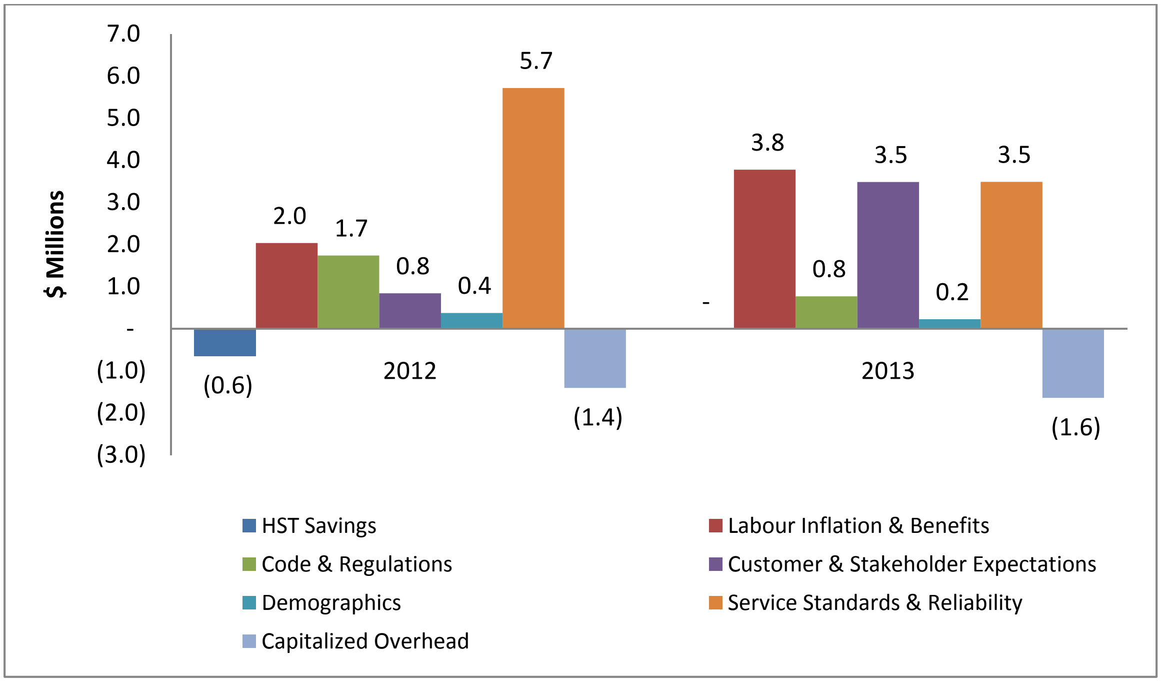
3.3.1.3 Operations and Maintenance Expenses

As discussed in Section 5.3, the 2012 and 2013 O&M expense forecasts have been developed in support of the Companies' business priorities and objectives, ensuring that O&M funding is appropriate and prioritized to meet the current and longer-term needs of customers. Key priorities and focus for the utilities in the near future include customer service repatriation; public and employee safety, customer satisfaction, financial management, environmental responsibility and system sustainment, and the demographic challenges we face with our aging workforce. The business drivers and their impacts on forecast O&M in 2012 and 2013 are summarized in

[25] Increase as compared to demand forecast embedded in 2011 rates, Section 7.1, Schedules 7 to 9

the figure below. As shown in Figure 3.3-4, the impact of changes in the O&M is an increase to the revenue requirements of $8.1 million in 2012 and $10.6 million in 2013, net of capitalized overhead.

Figure 3.3-4: O&M Funding Results in Increased Revenue Requirements[26]



The items in the figure above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

3.3.1.4 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in an increase to depreciation expense of $4.6 million. Additions in 2012 and 2013 have resulted in higher depreciation expense of $12.9 million in 2012 and a further $5.5 million in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all depreciation changes is an increase of $23.3 million in 2012 and a further $7.3 million in 2013.

The removal cost provision has increased $4.9 million in 2012 and a further $0.5 million in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost provision is $6.5 million in 2012 and a further $0.7 million in 2013.

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[26] Please refer to Section 5.3, Table 5.3-6 and Table 5.3-7

In addition, amortization expense has increased $11.6 million in 2012 and a further increase of $12.3 million in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. The four accounts listed in Table 3.3-3 are the key contributors to the increase in amortization expense in 2012 and are accounts that did not have amortization expense in 2011. The amortization expense in the IFRS Transitional account represents the amortization of the pension and OPEB transitional obligation as shown in Table 3.2-1.

Table 3.3-3: Accounting Impacts Drive Amortization Expense Increase in 2012[27]

($ millions) **Amortization Expense**	**2012**
IFRS Transitional Account	$ 7.1
Deferred Removal Costs	1.5
Gains and Losses on Asset Disposition	0.6
2010-2011 Customer Service O&M	2.9
	$ 12.1

The increase in 2013 amortization expense is largely driven by deferral accounts that had credit balances in 2011 and were fully amortized in 2012, such as the Property Tax Variance, Insurance Variance and Tax Variance accounts. The five accounts listed in Table 3.3-4 are the key contributors to the 2013 increase of $12.3 million in amortization expense.

Table 3.3-4: Change in Property Tax, Insurance and Tax Variance Accounts Drive Increase in 2013[28]

($ millions) **Amortization Expense**	**2012**	**2013**	**Change**
Property Tax Variance Account	$ (1.1)	$ (0.4)	$ 0.7
Insurance Variance Account	(1.2)	-	1.2
Tax Variance Account	(7.0)	-	7.0
Interest Variance Account	(2.5)	(1.7)	0.8
Energy Efficiency and Conservation	2.6	3.9	1.4
	$ (9.3)	**$ 1.9**	**$ 11.1**

The total impact on revenue requirement of changes in depreciation (including removal costs) and amortization is an increase of $41.5 million in 2012 and $20.3 million in 2013

27 Section 7.1, Schedules 68 to 71
28 Section 7.1, Schedules 28 and 29

3.3.1.5 Other Revenues

As discussed in Section 5.5, a significant increase in Other Revenue of $2.8 million in 2012 and a further increase of $1.7 million in 2013 is forecast. Increases in other revenue decrease the revenue requirement, offsetting the revenue deficiency. The increase in other revenue is largely attributable to revenue from natural gas for transportation service.

3.3.1.6 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increases of $0.6 million in 2012 and a further $1.6 million in 2013 both serve to increase revenue requirements. Other changes to income tax rates and adjustments to taxable income result in a decrease in revenue requirements in 2012 of $8.0 million and an increase in 2013 of $5.7 million. As shown in Table 3.3-5, the increase in CCA deductions, along with the deduction of removal costs and the reduction in the tax rate are the key components of the decrease in tax expense in 2012. The increase in CCA deductions is driven by the CCE Project. Changes in amortization and earned return are the key contributors to the tax expense increase in 2013.

Table 3.3-5: Components of 2012 and 2013 Tax Expense Changes[29]

($ millions)	**2012**	**2013**	**Total**
Reduction in Tax Rate	$ (2.0)	$ (0.5)	$ (2.5)
Increase in CCA Deductions	(13.1)	-	(13.1)
Removal Cost Deduction	(4.5)	-	(4.5)
Pension and OPEB	(1.5)	-	(1.5)
Changes in Amortization Expense	4.0	-	4.0
Changes in Earned Return	1.5	0.7	2.2
Other	0.2	3.4	3.6
	$ (15.5)	**$ 3.7**	**$ (11.8)**

3.3.1.7 Earned Return – Return on Rate Base and Financing Costs

Mainland earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change. The rate base proposals contained in Section 6, Rate Base contribute $4.1 million to the 2012 revenue requirement and a further $2.0 million to the 2013 revenue requirement.

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 5.7, Financing Costs and Return on Equity. The amount of financing

[29] Section 7.1 to 7.4, Schedules 30 to 35

required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. The growth in rate base increases financing costs by $4.1 million in 2012 and $0.9 million in 2013. This is offset in 2012 by a reduction in interest rates, mitigating this impact by $4.4 million with an increase of $1.1 million in 2013, resulting in a net decrease associated with financing costs of $0.3 million in 2012 and an increase of $1.9 million in 2013.

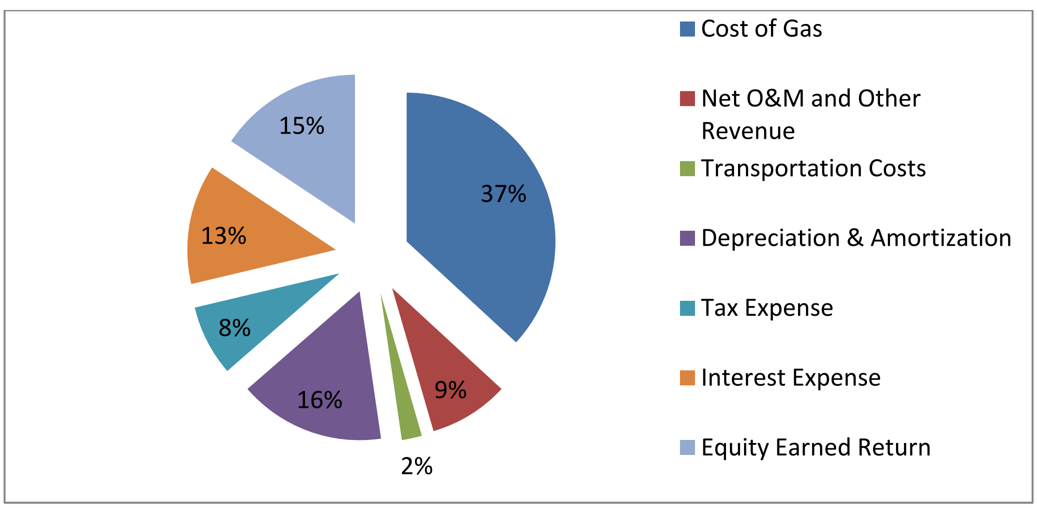
The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing non-bypass delivery rates.

3.3.2 SUMMARY OF VANCOUVER ISLAND REVENUE REQUIREMENTS

The FEU believe that the total revenue requirements of $195.1 million in 2012 and $214.1 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEVI to continue to meet the needs of our customers and the communities in which we serve. The following sub-sections will discuss the total Vancouver Island revenue requirement and revenue deficiency for 2013.

Figure 3.3-5 provides a breakdown of the components of the Vancouver Island total revenue requirement averaged for the two year period.

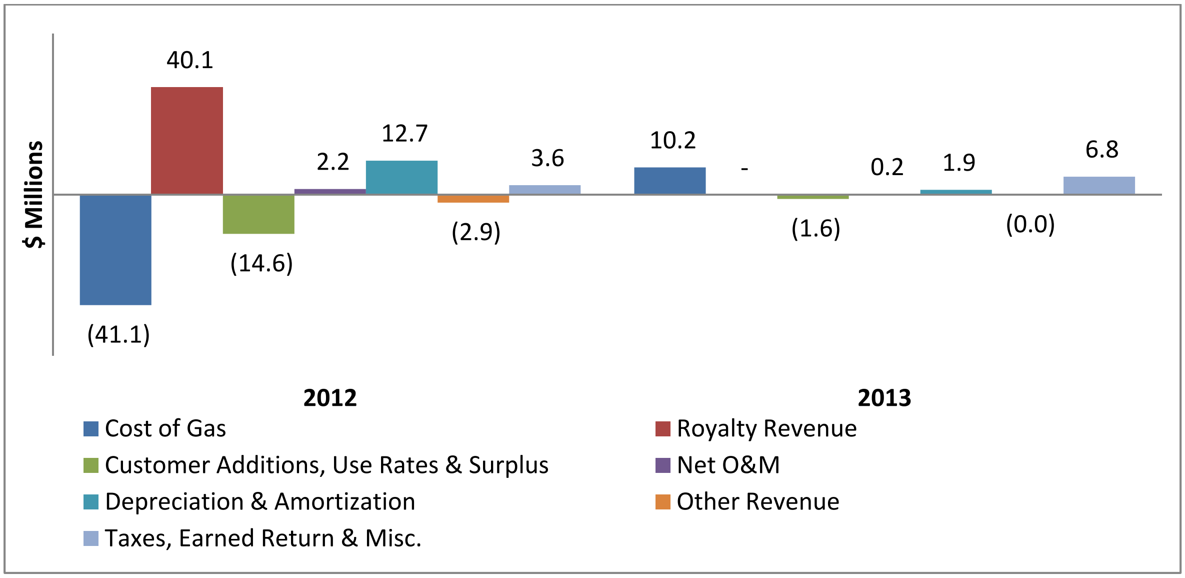
Figure 3.3-5: Average Composition of the 2012 and 2013 Vancouver Island Revenue Requirement[30]



[30] Section 7.2, Schedules 5 and 6

A revenue deficiency is not forecast for 2012; the $40.1 million deficiency that results from the loss of royalty revenues is offset by a $33 million reduction in the cost of gas and $8.1 million in amortization of the GCVA. The revenue deficiency in 2013 of $17.4 million is attributable to an increase in the cost of gas, the removal of the amortization of the GCVA, and tax expense and earned return increases, as displayed in Figure 3.3-6.

Figure 3.3-6: Loss of Royalty Revenues Offset by Reduction in Cost of Gas in 2012[31]



3.3.2.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4, is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 659 TJs lower than the demand forecast embedded in 2011 rates, with an increase of approximately 86 TJs in 2013. This decrease in demand is attributable to a reduction in use rates that is not offset by customer growth and results in a revenue deficiency of approximately $7.8 million in 2012 and a surplus of $1.6 million in 2013. In addition to the impacts of customer additions and use rates, the existing rates for Vancouver Island have the 2011 approved revenue surplus of approximately $22.4 million embedded within them, providing a net surplus associated with revenues at existing rates of $14.6 million in 2012 and $1.6 million in 2013.

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and has been properly reflected in the calculation of the Company's revenue requirement.

31 Section 7.2, Schedule 1

3.3.2.2 Cost of Gas

As discussed in Section 5.2, Vancouver Island's cost of gas reflects the costs related to commodity, transportation, and storage resources and the impacts of the hedging program. The Royalty Rebate arrangement under which Vancouver Island has received royalty revenues from the Province expires on December 31, 2011; therefore, the 2012 and 2013 forecast cost of gas does not include any royalty revenues. All else equal, the loss of the royalty revenues results in an approximate revenue deficiency of $40.1 million in 2012. As shown in Table 3.3-6, the revenue deficiency of $40.1 million associated with the loss of the royalty revenues is offset by a reduction in the cost of gas and the amortization of the GCVA, for a combined net reduction to the revenue requirement of approximately $1.0 million in 2012. With the GCVA fully amortized, the impact of cost of gas to the revenue requirement in 2013 is an increase of approximately $10.2 million.

Table 3.3-6: Reductions in Commodity Costs Offset the Deficiency Associated with Royalty Revenues in 2012[32]

($ thousands)

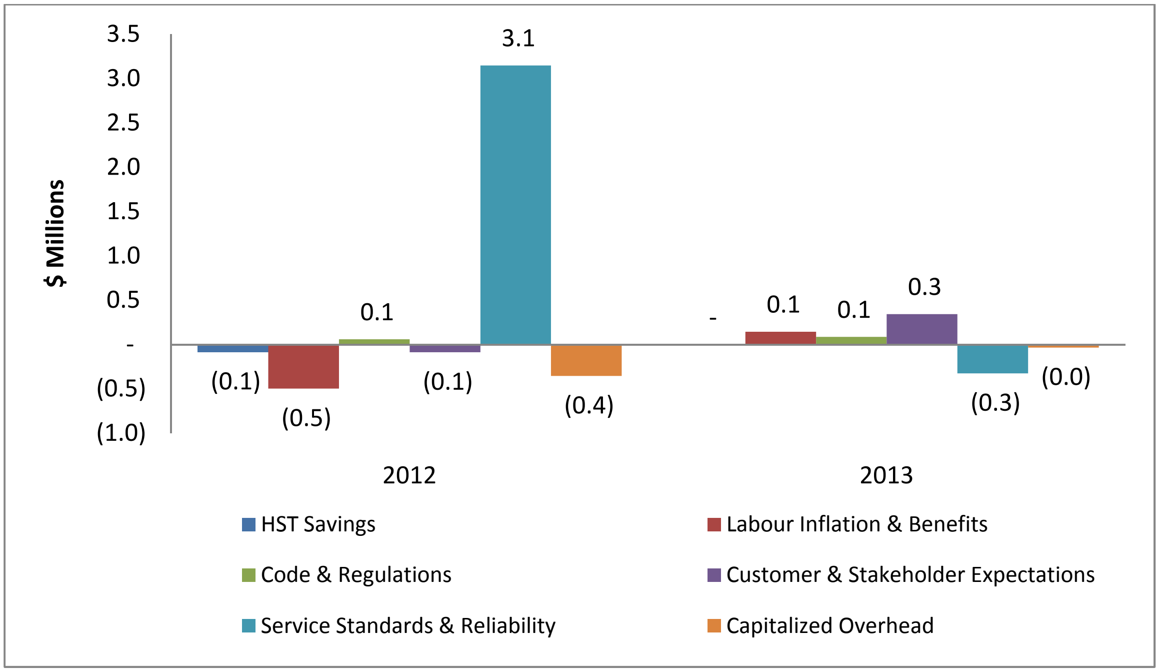
	2011 Approved	Increase (Decrease)	2012 Forecast	Increase (Decrease)	2013 Forecast
Cost of Gas	107,311	(32,974)	74,337	2,062	76,399
Royalty Revenues	(40,091)	40,091	-	-	-
Royalty Adjusted Cost of Gas	67,220	7,117	74,337	2,062	76,399
GCVA Amortization	-	(8,124)	(8,124)	8,124	-
Cost of Gas Revenue Requirement	67,220	(1,007)	66,213	10,186	76,399

3.3.2.3 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects the five key business drivers identified in Section 5.3. Forecast 2012 and 2013 revenue requirements changes associated with these O&M expenses are summarized in the figure below by these drivers, plus the impacts of HST in 2012. As shown in Figure 3.3-7, the impact of changes in the O&M is an increase to the revenue requirements of $2.2 million in 2012 and $0.2 million in 2013, net of capitaized overhead.

32 Section 7.2, Schedules 4-6 and Schedule 13

Figure 3.3-7: O&M Funding Results in Increased Revenue Requirements[33]



The items in the chart above are discussed more fully in Section 5.3, and have been reflected in the calculation of the Company's revenue requirement.

3.3.2.4 Transportation Costs

Vancouver Island transportation expenses are related to the Wheeling agreement between FEVI and FEI, the capacity right agreement between FEVI and BC Hydro, and motor fuel tax and social services tax on compressor and station fuel. A revenue requirement increase of approximately $360 thousand is forecast in 2012 with a further minor increase of $11 thousand in 2013, as shown in the table below.

Table 3.3-7: Transportation Cost Forecast for 2012 and 2013[34]

($ thousands) **Transportation Costs**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
FEI Wheeling Agreement	3,455	3,456	3,464
BC Hydro Capacity Right	375	244	244
Taxes on Compressor and Station Fuel	292	782	784
Total Transportation Expenses	**4,122**	**4,482**	**4,493**

[33] Please refer to Section 5.3, Table 5.3-8 and Table 5.3-9
[34] Section 7.2, Schedules 4 to 6

FEVI holds a Peaking Agreement with BC Hydro dated September 19, 2007 that provides FEVI limited access to a portion of BC Hydro's firm capacity under the Transportation Services Agreement during each winter period (November 1 to March 31). FEVI pays a Capacity Right Payment each month to BC Hydro whether or not it exercises its Capacity Right. The payment is comprised of a demand toll credit for the right to use peaking capacity and a carrying charge credit to BC Hydro to offset the carrying cost of the distillate required for fuel switching. For purposes of this submission, the forecast annual cost related to this capacity right is $244 thousand for 2012 and 2013.

3.3.2.5 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in a reduction to Vancouver Island depreciation expense of $0.3 million. Additions in 2012 and 2013 have resulted in higher depreciation expense of $3.9 million in 2012 and a further $1.1 million in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of all depreciation changes is an increase of $4.8 million in 2012 and a further $1.5 million in 2013.

The removal cost provision has increased $3.6 million in 2012 and a further $0.1 million in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost is $4.8 million in 2012 and a further $0.2 million in 2013.

In addition, excluding the GCVA, amortization expense has increased $2.9 million in 2012 and a further increase of $0.2 million in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. In addition to the end of the amortization of the 2009 revenue surplus on December 31, 2011 which results in an increase of $1.5 million to amortization expense, several other accounts contribute to the remaining increase of $1.4 million in 2012. Table 3.3-8 reflects accounts that have a significant impact on 2012 amortization expense. The amortization expense in the IFRS Transitional account reflects the amortization of the pension and OPEB transitional obligation as shown in Table 3.2-1. The increase of $0.2 million in 2013 is attributable to an increase in amortization expense of the EEC deferral account.

Table 3.3-8: Accounting Impacts Increase Amortization Expense in 2012[35]

($ millions) **Amortization Expense**	**2012**
IFRS Transitional Account	$ 0.9
Deferred Removal Costs	0.2
Gains and Losses on Asset Disposition	0.1
2010-2011 Customer Service O&M	0.3
	1.5
2009 Revenue Surplus (fully amortized)	1.5
Increase to Amortization Expense	**$ 3.0**

The total impact on revenue requirement of changes in depreciation and amortization is an increase of $12.7 million in 2012 and $1.9 million in 2013

3.3.2.6 Other Revenues

As discussed in Section 5.5, a significant increase in Other Revenue of $2.9 million in 2012 is forecast with no further change forecast in 2013. Increases in other revenue decrease the revenue requirement and offset the revenue deficiency. The increase in other revenue is attributable to a full year of LNG mitigation revenues from the Mount Hayes LNG facility in 2012 as compared to nine months of LNG mitigation revenues included in the approved 2011 revenue requirement.

3.3.2.7 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increases of $0.3 million and a further $0.4 million in 2013 both serve to increase revenue requirements. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $2.2 million and an increase in 2013 of $3.1 million. As shown in Table 3.3-9, the increase in CCA deductions, along with the amortization expense are the key contributors to the increase in tax expense in 2012. The increase in CCA is primarily attributable to the CCE Project and amortization expense is primarily attributable to the GCVA. Tax expense associated with the earned return has increased in 2012 because of the growth in rate base due to the Mount Hayes LNG Facility and the CCE Project as well as the impact of the expiration of the VINGPA earnings reduction. Changes in amortization and earned return are the key contributors to the tax expense increase in 2013.

[35] Section 7.2, Schedules 66 to 71

Table 3.3-9: Components of 2012 and 2013 Tax Expense Changes[36]

($ millions)	2012	2013	Total
Reduction in Tax Rate	$ (0.3)	$ (0.3)	$ (0.6)
Increase in CCA Deductions	(1.1)	(0.2)	(1.3)
Removal Cost Deduction	(0.1)	(0.0)	(0.1)
Pension and OPEB	(0.8)	0.1	(0.6)
Changes in Amortization Expense	(2.4)	3.0	0.6
Changes in Earned Return	3.0	0.4	3.4
Other	(0.5)	0.2	(0.3)
	$ (2.2)	**$ 3.1**	**$ 1.0**

3.3.2.8 Earned Return – Return on Rate Base and Financing Costs

Vancouver Island earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 4.0 per cent of that change. The rate base proposals contained in Section 6, Rate Base contribute $2.4 million to the 2012 revenue requirement and a further $1.0 million to the 2013 revenue requirement.

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, result in $1.3 million of additional financing costs in 2012 and $0.4 million of additional financing costs in 2013. Changes in interest rates mitigate this impact in 2012 by $1.9 and then increase by $1.7 million in 2013, resulting in a net decrease associated with financing costs of $0.6 million in 2012 followed by an increase of $2.2 million in 2013.

Furthermore, the return on equity reduction associated with the VINGPA adjustment comes to an end on December 31, 2011 and results in an increase to revenue requirement of $1.9 million in 2012.[37]

Although a revenue deficiency of $17.4 million in 2013 is forecast, Vancouver Island is seeking approval for the continuation of existing rates for 2012 and 2013. This is because the forecast

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[36] Section 7.2, Schedules 33 to 35

[37] OIC 1510 Special Direction:
3.1 (b) Adjustment to Cost of Service
For each year from January 1, 1996, to December 31, 2011, the return on the equity component of PCEC's rate base that would have been otherwise approved by the BCUC shall be reduced by the amount of $1,867,000. Such reduction shall not be recovered in whole or in part, directly or indirectly, through rates or tolls in any manner whatsoever.

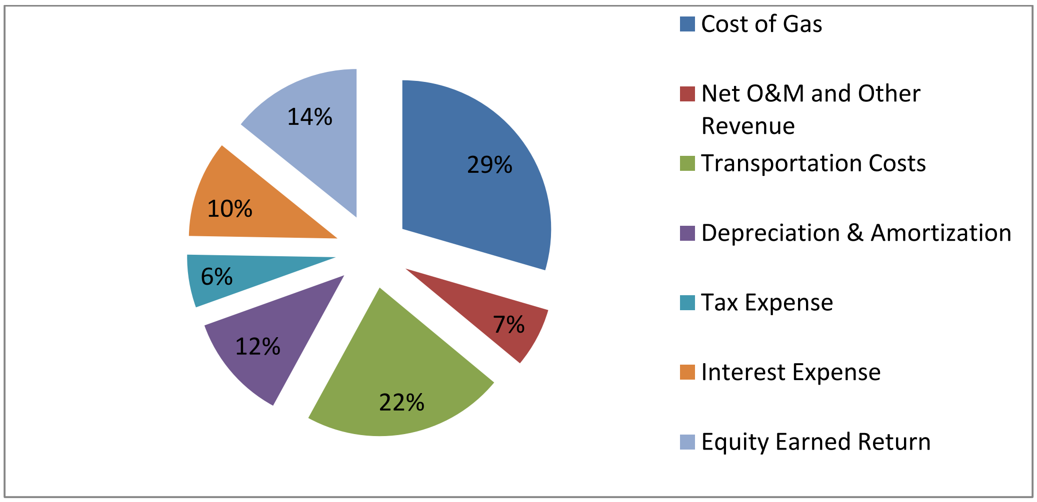
revenue deficiency described will be offset by part of the projected December 31, 2012 surplus balance of $71.6 million (before tax) in the RSDA. Section 3.4.2 provides a discussion on the RSDA and the 2012 and 2013 Vancouver Island rate proposals.

3.3.3 SUMMARY OF WHISTLER REVENUE REQUIREMENTS

The total revenue requirements of $11.4 million in 2012 and $12.2 million in 2013 have been calculated appropriately and reflect the reasonable costs required for FEW to continue to meet the needs of our customers in the Whistler area. The following sub-sections will discuss the total Whistler revenue requirement and revenue deficiencies for 2012 and for 2013.

Figure 3.3-8 provides a breakdown of the components of the Whistler total revenue requirement averaged for the two year period.

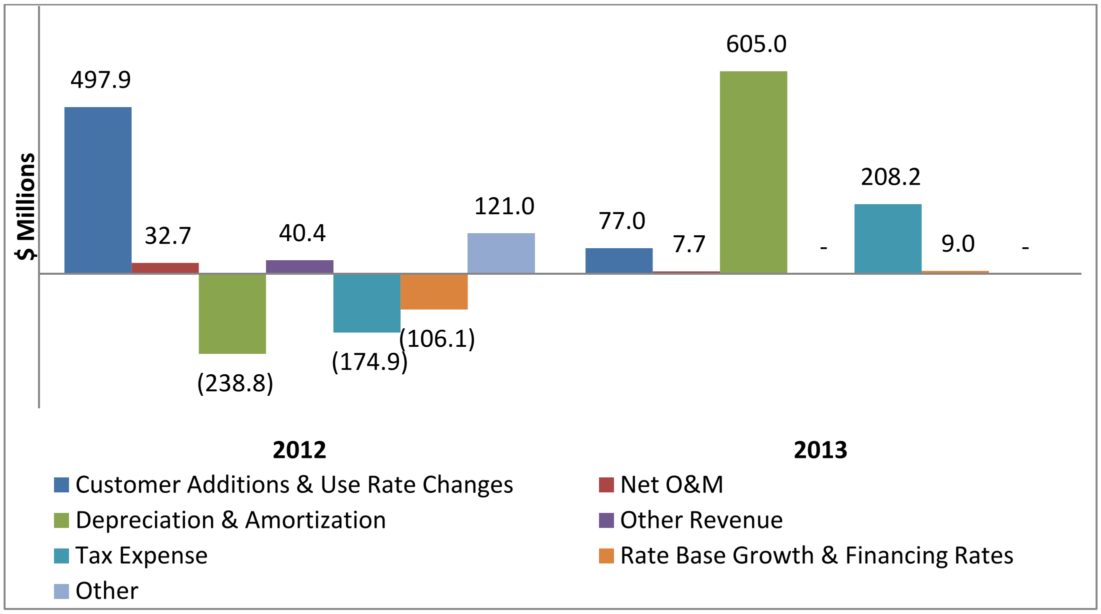
Figure 3.3-8: Average Composition of the 2012 and 2013 Whistler Revenue Requirement[38]



Changes to the Whistler revenue requirements result in revenue deficiencies of $172 thousand in 2012 and $907 thousand in 2013. These deficiencies are summarized in Figure 3.3-9 below.

[38] Section 7.3, Schedules 5 and 6

Figure 3.3-9: Whistler Revenue Deficiency Components[39]



3.3.3.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4 is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 48 TJs lower than the demand forecast embedded in 2011 rates, with a further decrease of approximately 7 TJs in 2013.[40] This decrease in demand is attributable to the projection for the use rate on an ongoing basis being lower than originally anticipated, as Whistler customers have consumed less natural gas than they had historically consumed propane. This trend has not been offset by customer growth. This decrease in demand results in a significant revenue deficiency of approximately $498 thousand in 2012 and $77 thousand in 2013.

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and have been properly reflected in the calculation of the Company's revenue requirement.

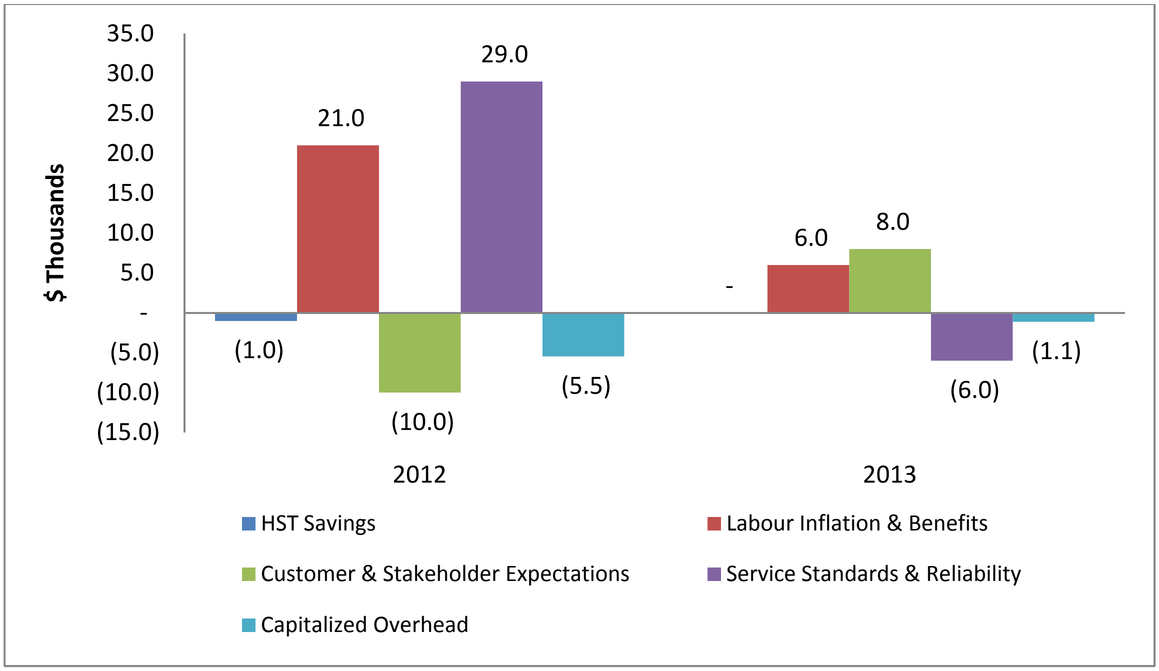
3.3.3.2 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects four of the key business drivers identified in Section 5.3. 2012 and 2013 revenue requirements are summarized in the figure below by these drivers, plus the impacts of HST in 2012. As shown in Figure 3.3-10, the impact of changes in the O&M

[39] Section 7.3, Schedule 1
[40] Section 7.3, Schedules 4 to 9

is an increase to the revenue requirement of $34 thousand in 2012 and $7 thousand in 2013, net of capitalized overhead.

Figure 3.3-10: O&M Funding Results in Increased Revenue Requirements[41]



The items in the chart above are discussed more fully in Section 5.3, and have been reflected in the calculation of the Company's revenue requirement.

3.3.3.3 Transportation Costs

Whistler transportation costs reflect the charge paid by Whistler to Vancouver Island for gas transportation service on the Whistler Pipeline. The transportation costs are forecast at approximately $2.6 million per year for 2012 and 2013, increasing the revenue requirement by $127 thousand in 2012.[42]

3.3.3.4 Depreciation and Amortization Expense

As discussed in Section 5.4, an update to the depreciation study has resulted in an increase to Whistler depreciation expense of $30 thousand. Additions in 2012 and 2013 have resulted in higher depreciation expense of $3 thousand in 2012 and a further $16 thousand in 2013. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement

41 Please refer to Section 5.3, Table 5.3-10 and Table 5.3-11
42 Section 7.3, Schedules 4 to 6

impact of all depreciation changes is an increase of $44 thousand in 2012 and a further $21 thousand in 2013.

The removal cost provision has increased $75 thousand in 2012 and a further $2 thousand in 2013. Similar to depreciation expense, the removal cost provision is not deductible for income tax purposes; therefore, the total revenue requirement impact of the removal cost is $100 thousand in 2012 and a further $3 thousand in 2013.

In addition, amortization expense has decreased $383 thousand in 2012 and increased $581 thousand in 2013. Both of these amounts are after-tax, so the impact to revenue requirements is as stated. The decrease in 2012 and corresponding increase is 2013, is largely attributable to the one year amortization of the credit balances in the Pipeline Cost Variance Account of $434 thousand and the Interest Variance account of $329 thousand. Please refer to Section 6.3 for a discussion of each of these accounts.

3.3.3.5 Other Revenues

As discussed in Section 5.5, a decrease in Other Revenue of $40 thousand in 2012 is forecast with no further change forecast in 2013. Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities.

3.3.3.6 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax reduction of $42 thousand in 2012 results in a decrease to the revenue requirement and is increased by $8 thousand in 2013. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $133 thousand and an increase in 2013 of $200 thousand.

3.3.3.7 Earned Return

Whistler earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 4.0 per cent of that change. The rate base proposals contained in Section 6, contribute an $18 thousand reduction to the 2012 revenue requirement and a further reduction of $26 thousand to the 2013 revenue requirement as costs associated with the Whistler natural gas conversion continue to amortize.

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, and changes in interest rates result in a net decrease associated with financing costs of $88 thousand in 2012 followed by an increase of $35 thousand in 2013.

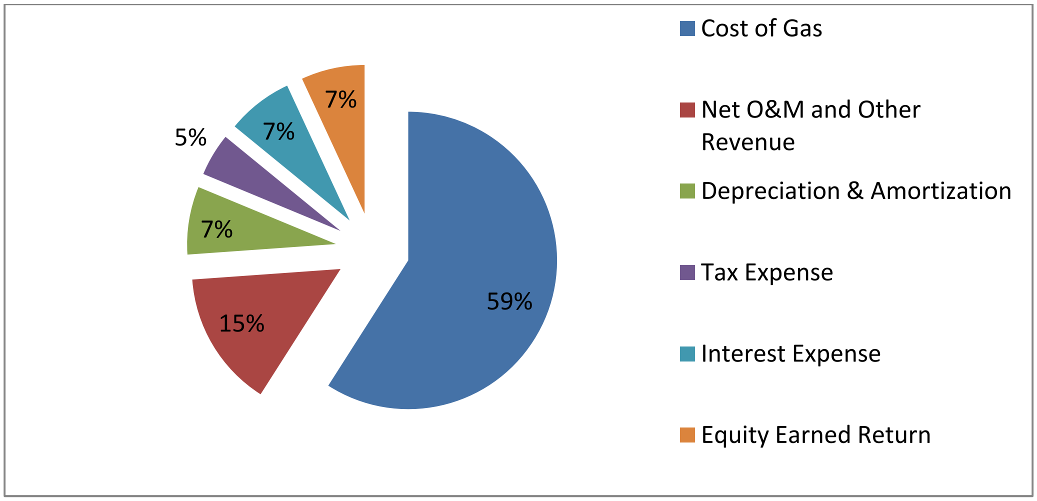
The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

3.3.4 SUMMARY OF FORT NELSON REVENUE REQUIREMENTS

The total revenue requirements of $4.9 million in 2012 and $5.0 million in 2013 have been calculated appropriately and reflect the reasonable costs required for Fort Nelson to continue to meet the needs of our customers. The following sub-sections will discuss the total Fort Nelson revenue requirement and revenue deficiencies for 2012 and for 2013.

Figure 3.3-11 provides a breakdown of the components of the Fort Nelson total revenue requirement averaged for the two year period.

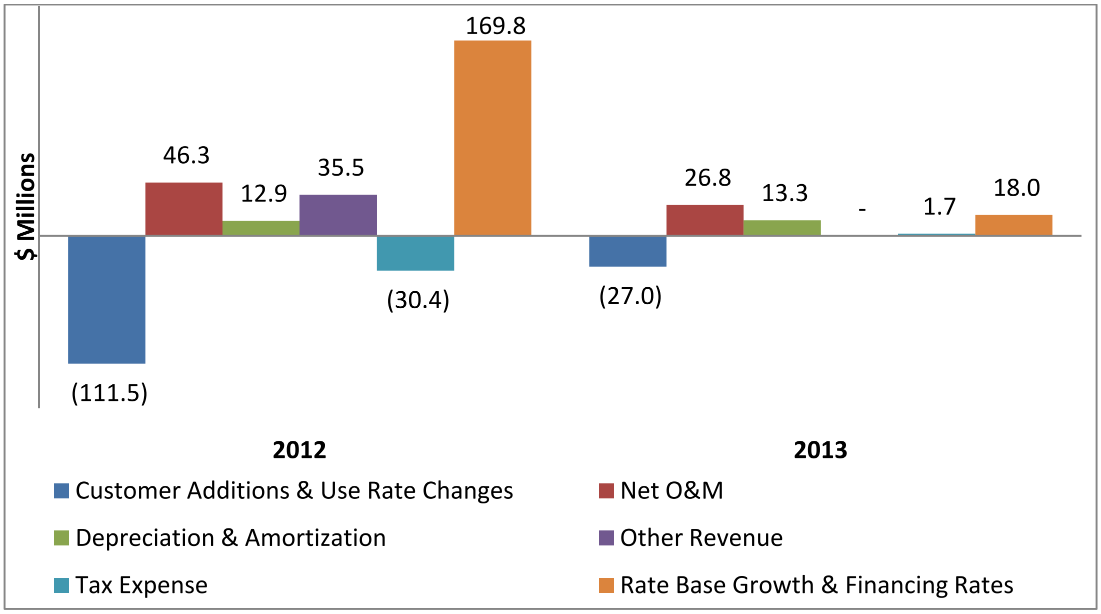
Figure 3.2-11: Average Composition of the 2012 and 2013 Fort Nelson Revenue Requirement[43]



Changes to the Fort Nelson revenue requirements result in revenue deficiencies of $122 thousand in 2012 and $33 thousand in 2013. These deficiencies are summarized in Figure 3.3-12 below.

[43] Section 7.4, Schedules 5 and 6

Figure 3.3-12: Fort Nelson Revenue Deficiency Components[44]



3.3.4.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4, is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 34 TJs greater than the demand forecast embedded in 2011 rates, with an increase of approximately 9 TJs in 2013. This increase in demand is attributable to customer growth and changes in use rates and results in a revenue surplus of approximately $112 thousand in 2012 and $27 thousand in 2013.[45]

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and has been properly reflected in the calculation of the Company's revenue requirement.

3.3.4.2 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects the two key business drivers identified in Section 5.3. 2012 and 2013 revenue requirements are summarized in the figure below by these drivers. As shown in Figure 3.3-13, the impact of changes in the O&M is an increase to the revenue requirement of $46 thousand in 2012 and $27 thousand in 2013, net of capitalized overhead.

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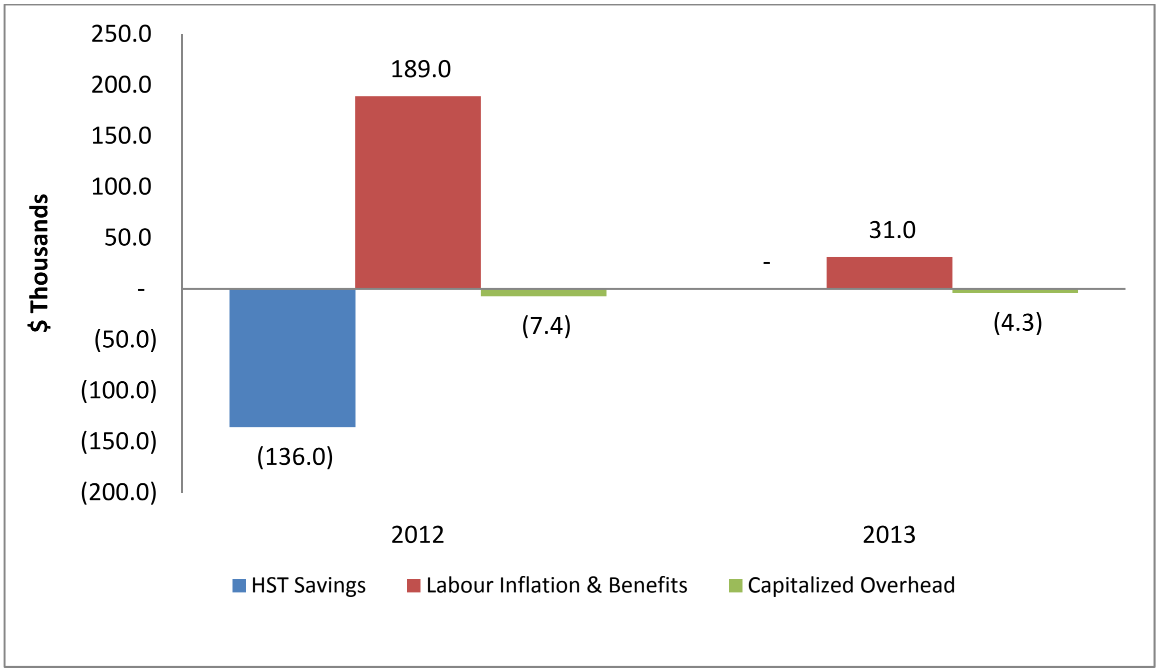
44 Section 7.4, Schedule 1
45 Section 7.4, Schedules 4 to 9

Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements[46]



The items in the chart above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

3.3.4.3 Depreciation and Amortization Expense

A full year of depreciation associated with the Muskwa River Crossing Project, as well as additions in 2012 and 2013, have resulted in higher depreciation expense of $68 thousand in 2012 and a further $10 thousand in 2013. This increase is offset by the impacts of the changes in depreciation rates which reduce the expense by $30 thousand. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of depreciation changes is an increase of $50 thousand in 2012 and a further $13 thousand in 2013.

In addition, amortization expense has decreased $37 thousand in 2012 with no further changes in 2013. This amount is after-tax, so the impact to revenue requirements is as stated.

[46] Please refer to Section 5.3, Table 5.3-12 and Table 5.3-13

3.3.4.4 Other Revenues

As discussed in Section 5.5, a decrease in Other Revenue of $36 thousand in 2012 is forecast with no further change forecast in 2013. Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities.

3.3.4.5 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increase of $7 thousand in 2012 and a further increase of $6 thousand in 2013 result in increases to the revenue requirement. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $37 thousand and a reduction in 2013 of $4 thousand.

3.3.4.6 Earned Return

Fort Nelson earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change. The rate base proposals contained in Section 6 increase revenue requirement by $78 thousand in 2012 and have a further increase of $9 thousand to the 2013 revenue requirement.

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, and changes in interest rates result in a net increase associated with financing costs of $92 thousand in 2012 followed by an increase of $8 thousand in 2013.

The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

3.3.5 SUMMARY OF AMALGAMATED COST OF SERVICE

As discussed in Section 1.2.5, in addition to seeking approval of rates for each of the FEU, we are also seeking approval of the amalgamated cost of service for 2013. This will form the first step of the Companies' plans to amalgamate, and will be followed by an application in Fall 2011 requesting approval to amalgamate with a rate design based on the amalgamated cost of service. As the FEU are seeking approval for the amalgamated cost of service prior to the merits of amalgamation being considered by the Commission, the FEU have phrased the approval requested in this application to be conditional upon the amalgamation being approved and going forward. The efficiency rationale for proceeding in this fashion is also discussed in Section 1.2.5.

In Section 3.3.5.1, the FEU provide a summary of the amalgamated cost of service. The amalgamated cost of service represents the summation of the Mainland, Vancouver Island, Whistler and Fort Nelson cost of service as described above, as well as adjustments to account for cost of service line items that will eliminate or change upon amalgamation.

3.3.5.1 FEU Amalgamated Cost of Service

The FEU amalgamated cost of service of $1.509 billion ($779.9 million delivery margin) is determined as follows:

Table 3.3-10: Amalgamated 2013 Cost of Service

		2013		
($ thousands)	**Reference**	**Total**	**Cost of Gas**	**Cost of Service[1]**
Mainland	*Section 7, Tab 7.1, Schedule 6, Column 5*	$ 1,282,763	$ 658,568	$ 624,195
Vancouver Island	*Section 7, Tab 7.2, Schedule 6, Column 5*	214,087	76,399	137,688
Whistler	*Section 7, Tab 7.3, Schedule 6, Column 5*	12,173	3,455	8,718
Fort Nelson	*Section 7, Tab 7.4, Schedule 6, Column 5*	5,001	2,945	2,056
		1,514,024	741,367	772,657
Add (Deduct):				
FEI (LNG Mitigation fee to FEVI)		-	(12,000)	12,000
Unaccounted for Gas (FEVI Wheeling Charge)		-	(144)	144
Other Cost of Service & Rate Base		(1,864)	-	(1,864)
FEW Transportation Charge		(2,585)	-	(2,585)
Squamish Transportation Charge		(414)	-	(414)
Total Amalgamation Adjustments		(4,863)	(12,144)	7,281
Amalgamated FEU Cost of Service		**$ 1,509,161**	**$ 729,223**	**$ 779,938**

[1] *Cost of service excluding cost of gas*

AMALGAMATION ADJUSTMENTS

The cost of service must be adjusted to reflect intercompany items that will be eliminated upon amalgamation and rate harmonization. In the case of shared services and wheeling or transportation charges between the Regions, the amalgamation of the entities results in the inter-company agreements ceasing to be in effect, and the need to retain them for regulatory purposes disappears upon amalgamation. In the case of the three items below, an adjustment must be made to the cost of service.

- The LNG mitigation revenues are included in the Vancouver Island delivery cost of service with the offset cost residing in the Mainland midstream costs. For purposes of this analysis, FEU has taken the approach of showing this $12 million adjustment to the delivery cost of service and cost of gas; however, the allocation of the LNG mitigation revenues as between midstream and delivery will be reviewed in the Fall 2011 Amalgamation and Rate Design Phase 'A' Application and may result in changes from what has been presented in this RRA.

- The unaccounted for gas associated with the FEVI Wheeling Agreement with FEI resides in the delivery cost of service in FEI, but as a cost of gas in FEVI, and has been adjusted accordingly.
- Other cost of service impacts from changes in cash working capital and tax expense occur. The cash working capital for the amalgamated cost of service is determined using the FEI approved Lead and Lag days. The capitalized overhead rate for the determination of tax expense and UCC additions is assumed to be FEI's rate of 8 percent. The FEW and Squamish Transport charges are accounted for as a cost in one utility but as a revenue in another; therefore the delivery cost of service has been adjusted to remove these costs.

The Companies do not expect that there will be material cost savings as a result of the amalgamation, since the operations and management of the utilities are already fully integrated and the savings have been captured for the benefit of customers over the 2004 through 2011 period; however, some small annual savings will be realized. These savings would be limited to reporting efficiencies such as financial, legal and regulatory reporting and debt issuance requirements. There will also be costs incurred to effect a future legal amalgamation of the Companies, if approved. For the one year of amalgamated cost of service (2013) relevant to this RRA, the costs and savings are expected to offset each other, and therefore the FEU have not forecast a change to the cost of service for this item. The FEU will capture any variances from the forecast of zero in a deferral account for future recovery from/return to customers. Although the costs related to the legal amalgamation are one-time in nature, any efficiency savings, although not large, will be ongoing, and will be included in future RRAs.

3.4 Rate Proposals

3.4.1 DELIVERY RATES

The proposed delivery rates reflect the revenue requirements for each Utility as discussed in Section 3.3. Preliminary bill impacts and tariff continuity schedules for all customers are provided in Appendix F-2, showing the annual bill impacts below. The following summary for each Utility provides the delivery rate change required and a summary of the annual bill impact of the rate proposals for an average residential customer in Mainland, Whistler, and Fort Nelson.

3.4.1.1 Mainland

The Mainland proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.0 per cent in 2012 and an additional effective base rate delivery increase of 6.4 per cent in 2013 (cumulative increase of 11.4 per cent).[47] These proposed increases result in changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.4 per cent or $24 in 2012 and an additional 3.0 per cent or $31 in 2013.[48]

3.4.1.2 Whistler

The Whistler proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 2.2 per cent in 2012 and an additional effective base rate delivery increase of 11.9 per cent in 2013 (cumulative increase of 14.1 per cent).[49] These proposed increases result in changes to the annual bill of an average Whistler residential customer with an approximate net increase of 1.5 per cent or $22 in 2012 and an additional 7.1 per cent or $115 in 2013.[50]

3.4.1.3 Fort Nelson

The Fort Nelson proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 6.5 per cent in 2012 and an additional effective base rate delivery increase of 1.6 per cent in 2013 (cumulative increase of 8.1 per cent).[51] These proposed increases result in changes to the annual bill of an average Fort Nelson residential customer with an approximate net increase of 2.3 per cent or $26 in 2012 and an additional 0.6 per cent or $7 in 2013.[52]

3.4.2 VANCOUVER ISLAND EFFECTIVE RATES

FEVI has been operating under the Vancouver Island Natural Gas Pipeline Act Special Direction[53] (the "Special Direction") since 1995.[54] The Special Direction is appended to the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA"), an agreement among the predecessor companies to FEVI, the Province, and (by assignment from Westcoast Energy Inc.) Fortis BC Holdings Inc. ("FHI"). The VINGPA contemplates the payment by the Provincial

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[47] Section 7.1, Schedules 2 and 3
[48] Appendix F-2, Tab 1.1.1 and Tab 1.2.1, Page 1
[49] Section 7.3, Schedules 2 and 3
[50] Appendix F-2, Tab 3.1 and Tab 3.2, Page 1
[51] Section 7.4, Schedules 2 and 3
[52] Appendix F-2, Tab 4.1.1 and Tab 4.2.1, Page 1
[53] OIC No. 1510 (Dec. 13, 1995).
[54] The Special Direction states that it shall cease to have any application after the latest of three conditions occurring: (a) the time when the balance of the RDDA has been reduced to zero; (b) the expiration/termination of the Joint Venture Transportation Service Agreement ("JV TSA"), but no later than January 1, 2011; or (c) the date of the termination of the Squamish Gas TSA. Although the RDDA has been reduced to zero and January 1, 2011 has passed, the Squamish Gas TSA continues to remain in effect thus keeping the Special Direction in effect.

Government of gas royalty revenues to FEVI through 2011, which are based on the wellhead price of gas until December 31, 2011, and have mitigated fluctuations in the cost of gas to the benefit of FEVI's Core Market customers. The Special Direction and the VINGPA contemplate the creation of the RDDA. The RDDA held Annual Revenue Deficiencies through 2002, and thereafter the Commission was directed by the Special Direction to set rates so as to permit the recovery of the Accumulated Revenue Deficiency in the RDDA over the shortest period reasonably possible, having regard to the competitive position of FEVI's rates relative to alternative energy sources and the desirability of reasonable rates for customers. The Core Market rates set by the Commission for FEVI under the Special Direction from 2003 to 2009 were based on the "Soft-Cap" mechanism and tied to electricity and fuel oil rates as competitive alternatives, appropriately recognizing the difficult competitive environment faced by FEVI. Although Core Market customer rates increased over time, the Soft-Cap ensured relative rate stability compared to competitive alternatives and volatile natural gas prices.

The 2010/11 RRA and RDA was FEVI's first rate application following the repayment of the RDDA. In that application, Vancouver Island developed and received approval for an interim rate mitigation strategy to offset the rate pressure resulting from the loss of the gas royalty revenues on December 31, 2011. This interim strategy resulted in a rate freeze for sales customers and the creation of a RSDA, to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. As demonstrated in Table 3.4-1, this was a successful strategy resulting in a projected after tax balance of $52.1 million at the end of 2011 to be used for future rate mitigation.

In this Application, Vancouver Island is seeking approval for a continuation of the existing rates for sales customers, Whistler and BC Hydro. The rates for VIJV and Squamish will remain in accordance with their respective Transportation Service Agreements. As discussed in Section 1.2.5, FEVI believes that a rate freeze is an appropriate rate mitigation strategy for the 2012 and 2013 forecast period in light of the continued long term significant upward pressure on rates for Vancouver Island customers, and continued pressure to remain competitive with other energy sources. FEU's plans to amalgamate via the forthcoming Amalgamation and Phase 'A' Rate Design Application in Fall 2011 which, if approved, will provide the long-term risk mitigation strategy for FEVI customers. A rate freeze for the next two year period will enable continued rate certainty for FEVI customer's until the longer term solution is in place. In the event that amalgamation is not approved, a two year rate freeze will enable natural gas on Vancouver Island to remain competitive with other energy sources for an additional 1-2 year period.

To achieve this rate freeze, the RSDA mechanism must remain in place for 2012 and 2013; FEVI is seeking approval for the continuation of the RSDA. The RSDA will continue to capture the differences in 2012 and 2013 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The existing surplus balance in the RSDA will be used to partly offset the forecast revenue deficiency in 2013 and results in forecast closing RSDA balances of $53.7 million, after tax in 2012 and $42.3 million, after tax in 2013.

Table 3.4-1: The RSDA Mitigates Rate Impacts Today and in the Future,

($ Thousands)	Actual 2010	Projected 2011	Forecast 2012	Forecast 2013
Opening RSDA Balance, net of tax	(3,300)	(35,618)	(52,066)	(53,668)
Annual (Surplus)/ Deficiency	(44,743)	(20,970)	4	17,436
Add: Interest on Balance	(457)	(1,408)	(2,140)	(2,338)
Less: Tax	12,882	5,930	534	(3,775)
Closing RSDA Balance, net of tax	**(35,618)**	**(52,066)**	**(53,668)**	**(42,344)**
Tax Rate	28.5%	26.5%	25.0%	25.0%
Closing RSDA Balance, before tax	**(49,816)**	**(70,838)**	**(71,557)**	**(56,459)**

As discussed in Section 1.2.5, using the existing low cost of gas as the base case, the future rate impacts expected for Vancouver Island are still in the range of a 20 percent increase over the next several years. This impact will be magnified, and may be doubled, should increases in the cost of gas occur. Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers.

3.4.3 DELIVERY RATE RIDERS

3.4.3.1 Mainland

The Mainland RSAM Rider reflects a projected balance of $8.4 million owing to customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.032/GJ in 2012 applicable to Rate Schedules 1, 1B, 1U, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23; the 2013 Rider will be set as part of FEI's Fourth Quarter 2011 Gas Cost report.[55] The change in the RSAM rider results in a decrease to the annual bill of an average Lower Mainland residential customer of 0.1 percent or $1 in 2012.[56]

As shown in Appendix F-2, the expiry of the Mainland Earnings Sharing Mechanism credit rider will result in a nominal increase to the annual bills of Mainland non-bypass customers. The expiry of this riders results in changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 0.5 per cent or $5 in 2012.[57]

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55 Section 7.1, Schedule 85
56 Appendix F-2, Tab 1.1.1, Page 1
57 Ibid

3.4.3.2 Whistler

The Whistler RSAM Rider reflects a projected balance of $0.8 million recoverable from customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances are requested to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a debit rider of $0.524/GJ in 2012 applicable to all Whistler customers; the 2013 Rider will be set as part of FEW's Fourth Quarter 2011 Gas Cost report.[58] The impact of the RSAM rider is significant and results in an increase to the annual bill of an average Residential Whistler customer of 3.2 per cent or $47 in 2012.[59]

3.4.3.3 Fort Nelson

The Fort Nelson RSAM Rider reflects a projected balance of $16.0 thousand owing to customers at December 31, 2011. As noted in Section 6.3.1.3, RSAM account balances will continue to be recovered from or returned to customers through Delivery Rate Rider 5 over a three year period. This results in a credit rider of $0.011/GJ in 2012 applicable to Rate Schedules 1, 2.1, 2.2 and 25; the 2013 Rider will be set as part of Fort Nelson's Fourth Quarter 2011 Gas Cost report.[60] The impact of the RSAM rider results in a decrease to the annual bill of a Residential Fort Nelson customer of 0.5 per cent or $6 in 2012.[61]

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[58] Section 7.3, Schedule 85
[59] Appendix F-2, Tab 3.1, Page 1
[60] Section 7.4, Schedule 85
[61] Appendix F-2, Tab 4.1.1, Page 1

4 DEMAND FORECAST AND REVENUES AT EXISTING RATES

4.1 Introduction to Demand Forecast and Revenues at Existing Rates

This section provides a discussion of the demand for natural gas, comprised of natural gas sales and transportation volumes forecast for 2012 and 2013. The forecast of demand for natural gas is an important component of the RRA and is derived from the following two inputs:

- The forecast number of customers and customer additions; and
- The forecast average Use Per Customer ("UPC") by customer class.

The forecast number of customers and customer additions are key cost drivers for both operating and capital costs incurred serving our customers. Additionally, the forecast demand is a key input in the determination of the delivery rates needed to recover the revenue requirements for 2012 and 2013. Revenues and margin referred to in this section mean revenues and margin at existing rates for 2011.

All regions are forecast to experience a slight increase in consumption except Whistler, where consumption is forecast to decline by 1 percent from 2012 to 2013. The forecast increases in consumption drive delivery rates lower, all else equal. The forecast of demand for natural gas included in the RRA is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for the forecast period. The forecast of demand for natural gas included in this RRA fairly represents the expected customer additions and average UPC for 2012 and 2013, and is the most appropriate forecast of demand for natural gas to be used in the determination of rates for the 2012 and 2013 forecast period.

The remainder of this chapter is organized as follows:

- Section 4.2 - Overview of Total Energy Demand By Region
- Section 4.3 - Underlying Forecast Methodology
- Section 4.4 - Mainland (Demand Forecast and Revenues)
- Section 4.5 - Vancouver Island (Demand Forecast and Revenues)
- Section 4.6 - Whistler (Demand Forecast and Revenues)
- Section 4.7 - Fort Nelson (Demand Forecast and Revenues)

4.2 Overview of Total Demand Forecast by Region

Below, the Companies provide an overview of the demand forecast and its drivers in 2012 and 2013. The data is presented for the Companies individually and on a combined basis. The detailed explanations for the forecasts are provided in subsequent sections.

The following Table 4.2-1 shows the total energy demand for the Companies for the forecast period, and illustrates that all regions are forecast to experience a slight increase in consumption except Whistler, where consumption is forecast to decline by 1 percent from 2012 to 2013. It should be noted, that the forecast demand in this section for FEI does not include new customer additions or new energy demand for CNG and LNG service that is presented in Section 5.5.5 (Other Revenue – Mainland – Natural Gas for Transportation Service Revenue) and Appendix I (CNG and LNG Fueling Report). However, existing or historical natural gas for transportation customers under Rate Schedule 6 or Rate Schedule 25 have been included.

Table 4.2-1: The Companies – Forecast Total Energy Demand[62]

(In TJs)		2010 Actual	2011 Forecast	2012 Forecast	2013 Forecast
Mainland					
	Residential	70,041	70,003	69,890	69,817
	Commercial	46,643	46,790	47,059	47,332
	Industrial	51,538	51,226	51,547	51,559
	Mainland Total	**168,222**	**168,019**	**168,496**	**168,707**
Vancouver Island					
	Residential	4,698	4,630	4,576	4,528
	Commercial	7,051	7,066	7,198	7,333
	Industrial	19,526	22,295	22,295	22,295
	Vancouver Island Total	**31,275**	**33,991**	**34,069**	**34,156**
Whistler					
	Residential	224	230	237	244
	Commercial	541	500	480	465
	Whistler Total	**765**	**731**	**716**	**709**
Fort Nelson					
	Residential	271	273	273	274
	Commercial	288	296	304	312
	Industrial	55	55	55	55
	Fort Nelson Total	**615**	**624**	**633**	**642**
The Companies Total		**200,877**	**203,365**	**203,914**	**204,214**

For Mainland, an increase in commercial Rate Schedule 23 use per customer has resulted in increased demand for the commercial rate class, offsetting declining or relatively stable demand in residential rate class and other commercial rate schedules.

62 Sections 7.1 to 7.4, Schedule 7-9

For Vancouver Island, rising UPC in almost all Commercial Rate Schedules has helped offset the declining demand in the Residential Rate Schedule that is forecast to occur as a result of the continuing declining UPC. Following the recent volatility in both the housing market and UPC, Vancouver Island observed some returning stability in 2010. However in 2011, the industrial rate class, based on transportation contract demand, is projected to increase by 15 percent compared to 2010 actual resulting in an overall increase of 9 percent for Vancouver Island compared to 2010. For 2012 and 2013, total demand remains relativity flat for FEVI as a whole.

For Whistler, declining use per customer in the Commercial Large General Service Rate Schedules ("LGS-2" and "LGS-3") combined with reduced customer additions offset increases seen in the other commercial and residential Rate Schedules, resulting in overall reduced demand.

For Fort Nelson, an increasing UPC in commercial Rate Schedule 2.2 drove the increase in demand for this region.

As shown in the following Table 4.2-2, net customer additions for all Companies are expected to drop slightly in 2011 compared to 2010. For 2012 and 2013, net additions are forecast to rebound to and then exceed 2010 levels. Forecast additions are up significantly from the 8,144 customers added in 2009 but fall short of the 12,775 customers added in 2008.

Table 4.2-2: The Companies – Forecast Customer Additions

	2010 Actual	2011 Forecast	2012 Forecast	2013 Forecast
Mainland	6,913	6,317	6,656	6,923
Vancouver Island	2,432	2,422	2,557	2,658
Whistler	12	18	19	19
Fort Nelson	21	23	22	24
All Companies	**9,378**	**8,780**	**9,254**	**9,624**

The following Table 4.2-3 describes the existing Rate Schedules included in each of the three rate groups (Residential, Commercial, Industrial) for the four regions[63] discussed in this section.

[63] Note: The Mainland region presented in this section includes the Lower Mainland, Inland, Columbia and Revelstoke regions.

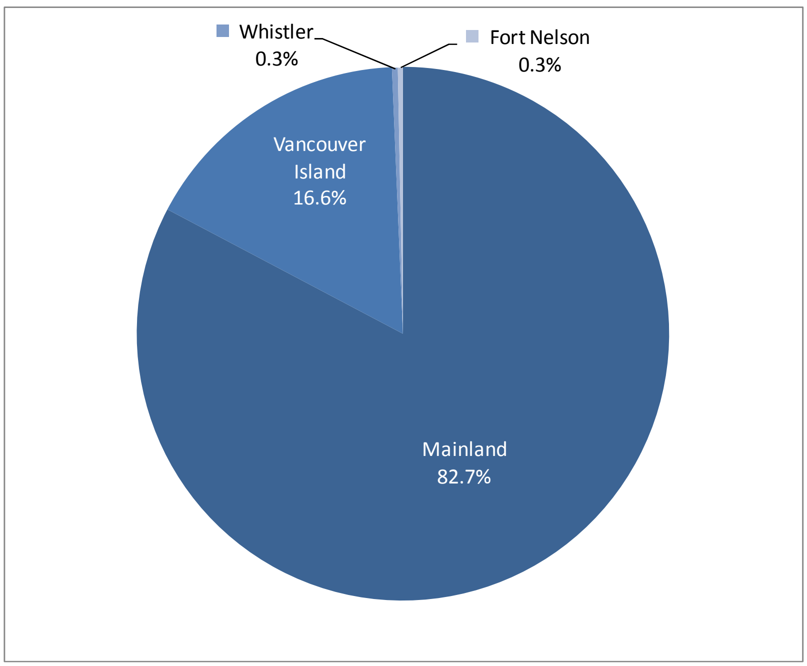
Table 4.2-3: The Companies – Rate Schedule Classification*

	Mainland	Vancouver Island	Whistler	Fort Nelson
Residential	1	RGS-1	SGS-1 Res	1
Commercial	2, 3, 23	AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, HLF, ILF	SGS-1 Com, LGS-1, LGS-2, LGS-3	2.1, 2.2
Industrial	4 ,5, 6, 7, 22, 25, 27	TPT		25

* Note: Rate Schedule 16 has not been included because it is a supply offering for LNG and not a delivery service or transportation rate schedule like Rate Schedule 23 or Rate Schedule 25, for example.

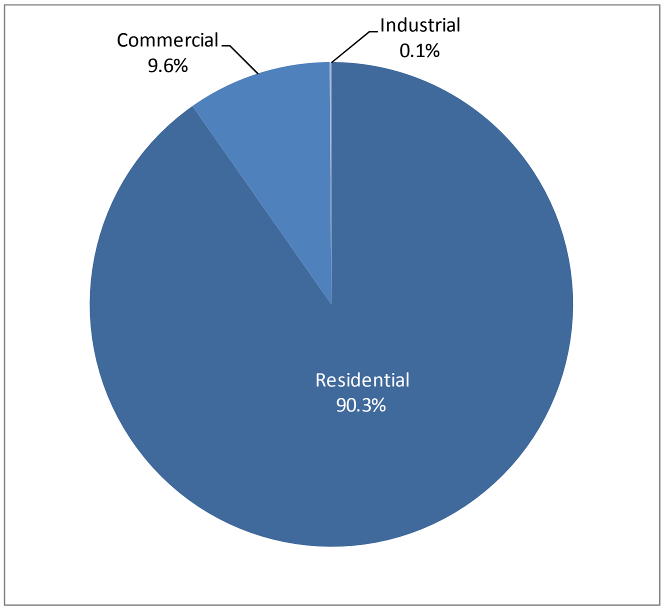
The forecast energy demand by company for 2012 is shown in the Figure 4.2-1 below. Whistler and Fort Nelson account for 0.6 percent of the total energy demand forecast for the Companies, with the Mainland making up about 83 percent of the total energy demand.

Figure 4.2-1: Total Demand Split between Companies



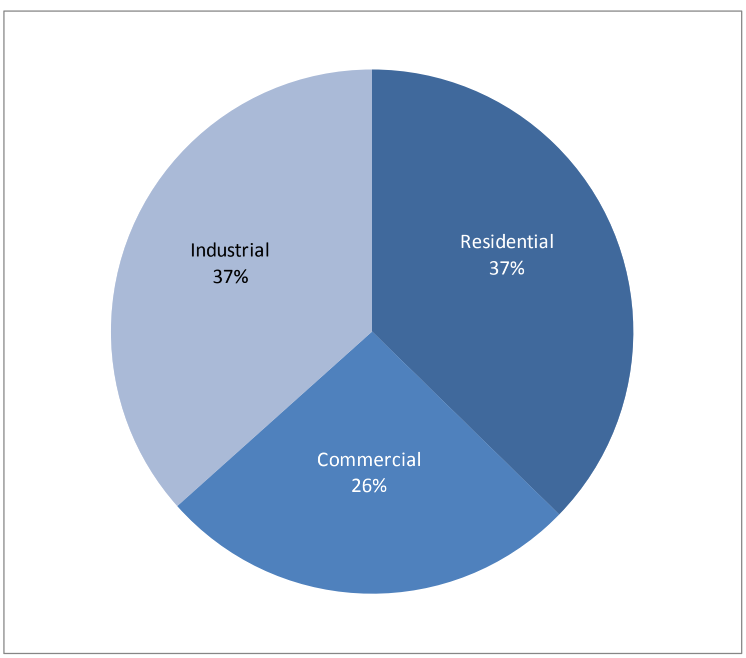
For 2012 just over 90 percent of the Companies' customers are forecast to be residential. 9.6 percent, or just over 93,000 customers, are in the Commercial Rate Schedules while 1,023 are in Industrial Rate Schedules. The split is shown in Figure 4.2-2 below:

Figure 4.2-2: Total Customer Split between Rate Groups, All Companies



The forecast energy demand by rate group for 2012 is shown in Figure 4.2-3 below. The split between Residential, Commercial and Industrial energy demand for all Companies forecast for 2012 remains consistent with prior years. The Residential and Industrial rate classes each account for 37 percent of the demand and the Commercial classes account for the remaining 26 percent.

Figure 4.2-3: Total Demand Split between Rate Groups, All Companies



The slight increase in total throughput across all regions, except for Whistler, has a positive impact in reducing delivery rates, all else equal, for 2012 and 2013. The Companies will provide an updated forecast if there are any material changes in the forecast inputs as the regulatory process unfolds through the summer and fall of 2011.

4.3 Underlying Forecast Methodology

The forecasts summarized above were prepared according to the methodology used in prior RRAs. It involves two major steps:

1. Forecast account additions, use rates and Industrial demand using methodologies that are consistent with past forecasts. These methodologies result in demand forecasts for each region and rate class. The aggregate energy forecast for each region and rate class is the summation of three separate demand forecasts as follows:
   - The forecast **Residential Energy Demand** is the product of the residential accounts (including account additions) and the normalized forecast Residential use rate.
   - The forecast **Commercial Energy Demand** is the product of the Commercial accounts (including account additions) and the normalized forecast Commercial use rate, for each Commercial rate schedule.
   - The forecast **Industrial Energy Demand** is the forecast demand reported through the Industrial Survey.
2. Compare the independently developed forecast with historical normalized data. Through this comparison the forecast for gas usage by our customers is verified. The tables and figures presented in Section 4, all show the historical values recorded by the Companies along with the forecast value for 2011, 2012 and 2013.

The following section discusses the methodology used to prepare the demand forecast. The methodology described in this section applies to all three Companies. The Companies believe it is reasonable to use the existing forecast methodology that has been reviewed and accepted internally, and has been reviewed and accepted by the BCUC and stakeholders in past regulatory proceedings, including the most recent RRA's for each of the Companies.

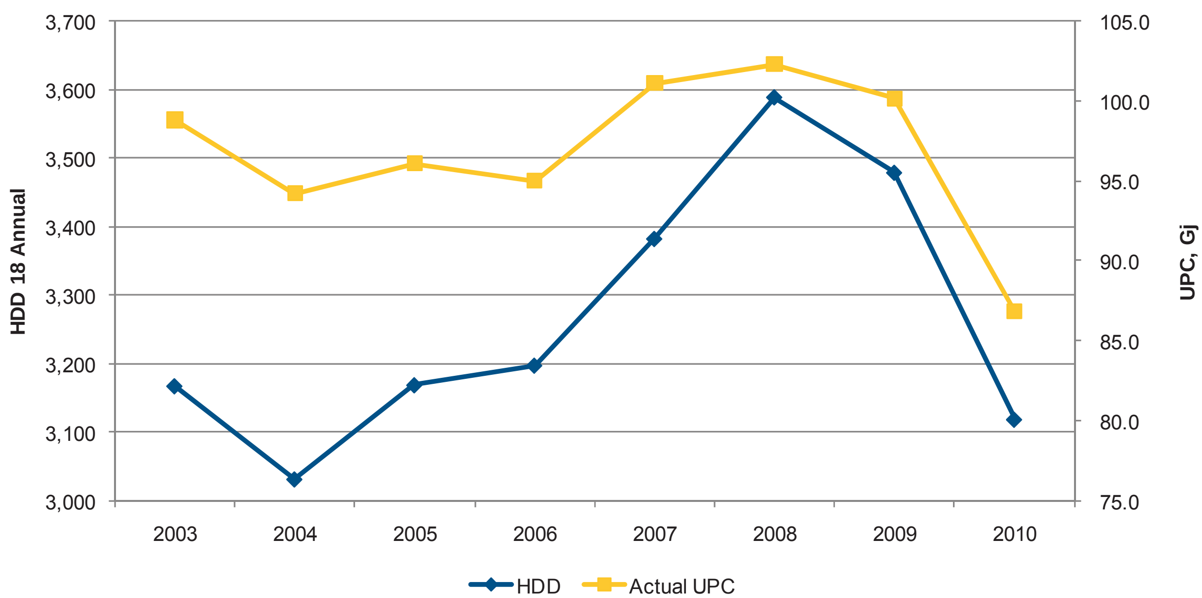
4.3.1 AVERAGE USE PER CUSTOMER FORECAST METHODOLOGY

The forecast UPC is one of two key inputs for both the residential and commercial demand forecast. The forecast UPC is multiplied by the total customer accounts in each region and rate schedule to determine the demand in those regions and rate schedules. The forecast of average usage per customer is based upon an analysis of weather normalized consumption data. Normalized UPC forecasts are developed for all Residential and Commercial rate classes.

Normalization is the process that allows us to compare use per customer in different years irrespective of the weather. Normalization essentially removes the weather as a factor from use per customer, allowing us to compare UPC rates from different years and between different regions and rates.

The following figure compares the actual residential demand with the annual heating degree days (HDD). Higher HDD totals indicate a colder year. As can be seen, the residential demand closely follows weather patterns.

Figure 4.3-1: Annual HDD Correlates Well to Actual Residential Demand

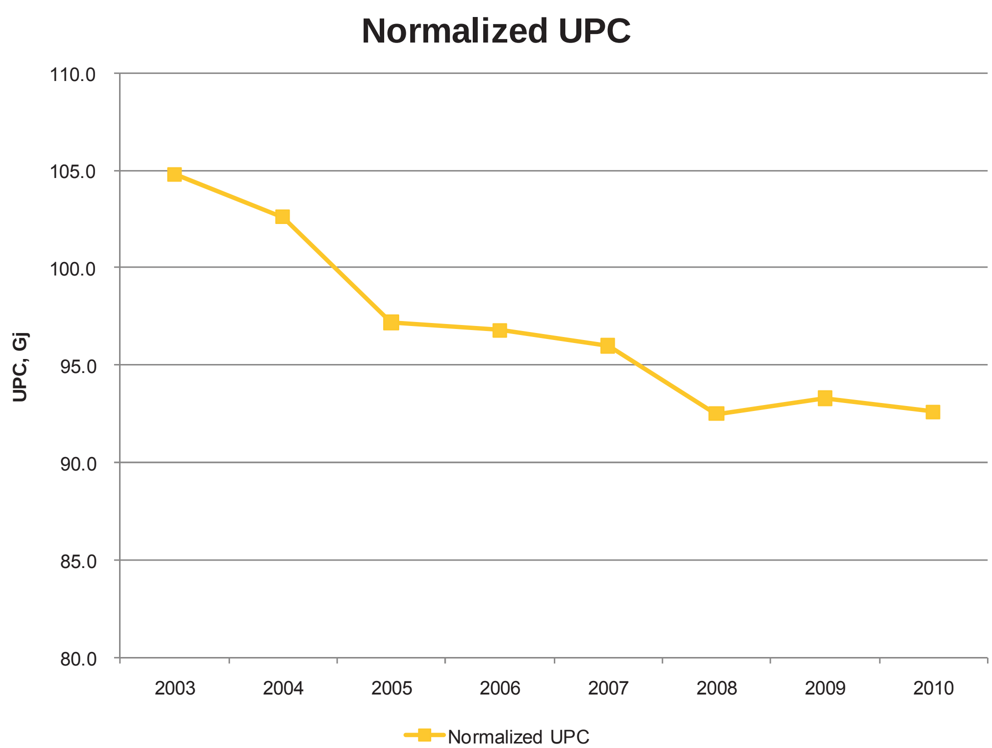


In colder years such as 2008, residential demand increases. In warmer years such as 2010, residential demand decreases.

Given the influence of the weather, it is not possible to make an accurate prediction about future demand based on the historical actual demand. We need to first normalize the demand by removing the weather effect. Once this is done, the normalized UPC may reveal other trends that are present in the data, such as reduced consumption resulting from improved appliance efficiency.

The following figure shows UPC resulting from the same annual demand on a weather normalized basis.

Figure 4.3-2: Normalized Use Rate Per Customer



From the figure above we can see that there is a clear and consistent downward trend in use per customer irrespective of annual weather. In rate schedules where a consistent trend is not identifiable a three year average UPC is used. Consistent with past practices and industry standards, and dating back to Mainland's 1992 Revenue Requirement Application, which was approved by Commission Order No. G-63-92 on August 5, 1992, the Companies use the previous 10 years of weather data for normalization.

The Companies believe that efficiency improvements are a key driver of the decline in Residential average UPC. These would include the retrofit of older, less efficient appliances with new high efficiency units, and also upgrades to insulation, window, doors, and, more generally speaking, building shells. Although efficiency improvements are driven by a number of factors such as technological advances, natural gas prices, public policies/programs and the state of the economy, they are also influenced by Mainland and Vancouver Island's EEC programs.[64] Since the Companies recently received approval for EEC programs that have significantly greater levels of funding, it is reasonable to assume that these will impact average UPC over the forecast period. In 2010 the impact was estimated to be a 0.12 Gigajoule ("GJ") decline in Residential average UPC. In 2011 the impact is forecast to be a 0.16 GJ decline in Residential

[64] EEC Programs have been established in Mainland and Vancouver Island regions.

average UPC. While EEC savings are not a direct input into the forecast model, their effect is implicit in the generally declining UPC trends.

4.3.2 RESIDENTIAL CUSTOMER ADDITIONS FORECAST METHODOLOGY

Residential customer additions and the existing residential customer totals are the second key input in the residential demand forecast. The customer count (including additions) is multiplied by the average use per customer to form the residential demand forecast.

The housing market is forecast by Canada Mortgage and Housing Corporation ("CMHC") to stabilize in 2011 and strengthen in 2012. The level of new home construction will trend higher during the next two years, resulting in housing starts reaching their ten-year average. According to CMHC housing starts are expected to reach 26,900 homes in 2011 and 29,000 homes in 2012.

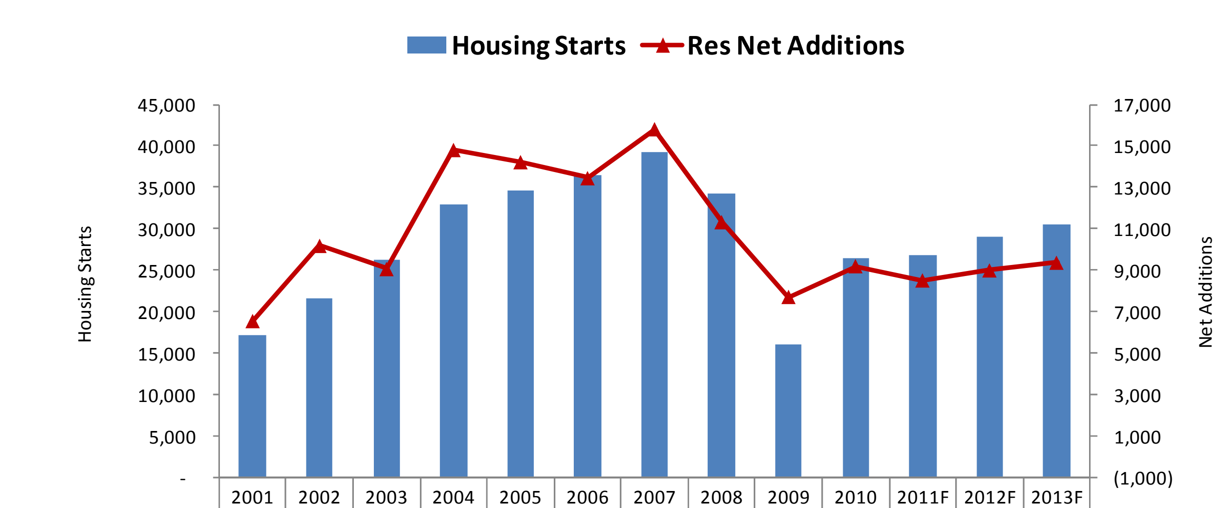
In order to forecast customer additions, we continue to use the housing starts forecasts from the CMHC and the Conference Board of Canada ("CBOC"). The forecast provides separate single family and multi-family residential estimates.[65]

We have developed separate single and multi family dwelling forecasts for this filing. These two forecasts are based on our own internal customer mix for these dwellings as well as the CMHC and the CBOC forecast for growth in these two housing types. Once the separate forecasts are completed the accounts are combined for the two housing types and become the Rate Schedule 1 Residential accounts forecasts.

The following chart shows the relationship between the total housing starts and historical Rate Schedule 1 net customer additions for the period 2002 to 2010. The forecast starts and customer additions are shown for 2011-2013.

[65] Conference Board of Canada Long Term Housing Starts Singles Forecast dated January 13, 2011 and Conference Board of Canada Long Term Housing Starts Multiples Forecast dated January 13, 2011, refer to Appendices C-1 and C-2.

Figure 4.3-3: Customer Additions Correlate Well with Housing Starts for All Companies



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Housing Starts	17,234	21,625	26,174	32,925	34,667	36,443	39,195	34,321	16,077	26,479	26,900	29,000	30,491
Res Net Additions	6,554	10,180	9,061	14,798	14,214	13,439	15,801	11,318	7,723	9,198	8,517	8,996	9,366

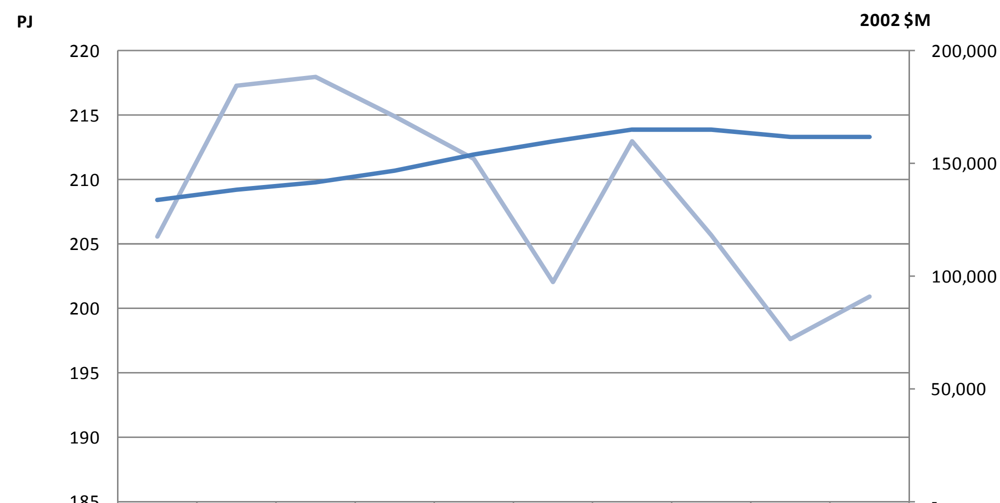
The above figure demonstrates the continued strong correlation between housing starts and net Residential customer additions. The correlation statistic is over 90 percent. For this reason the CMHC and the CBOC housing starts forecast are an appropriate predictor of future customer additions for all the Companies.

The growth rates of provincial housing starts are used as proxies of the Companies' customer additions forecast. The preliminary forecast is then reviewed by internal staff who have more insights into regional housing markets. These reviews allow us to make adjustments to the forecast based on our detailed knowledge of regional trends.

4.3.3 GDP CORRELATION TO DEMAND

While historically, provincial GDP growth has provided a directional measure of the overall economy, it is not a discrete input into our forecasting model. The following figure shows normalized demand and provincial GDP. While the GDP has grown steadily since 2002, total demand has fallen from a peak of 218 Petajoules ("PJs") in 2003 to 201 PJs last year.

Figure 4.3-4: Provincial GDP Does Not Correlate to Normalized Demand



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy Demand	206	217	218	215	212	202	213	206	198	201
GDP	133,403	138,193	141,435	146,541	153,489	159,729	164,496	164,869	161,851	161,850

Further, forecasting natural gas prices and the impact to industrial demand is not a direct input into the forecast model, but are implicit in the survey responses received from the individual industrial customers.

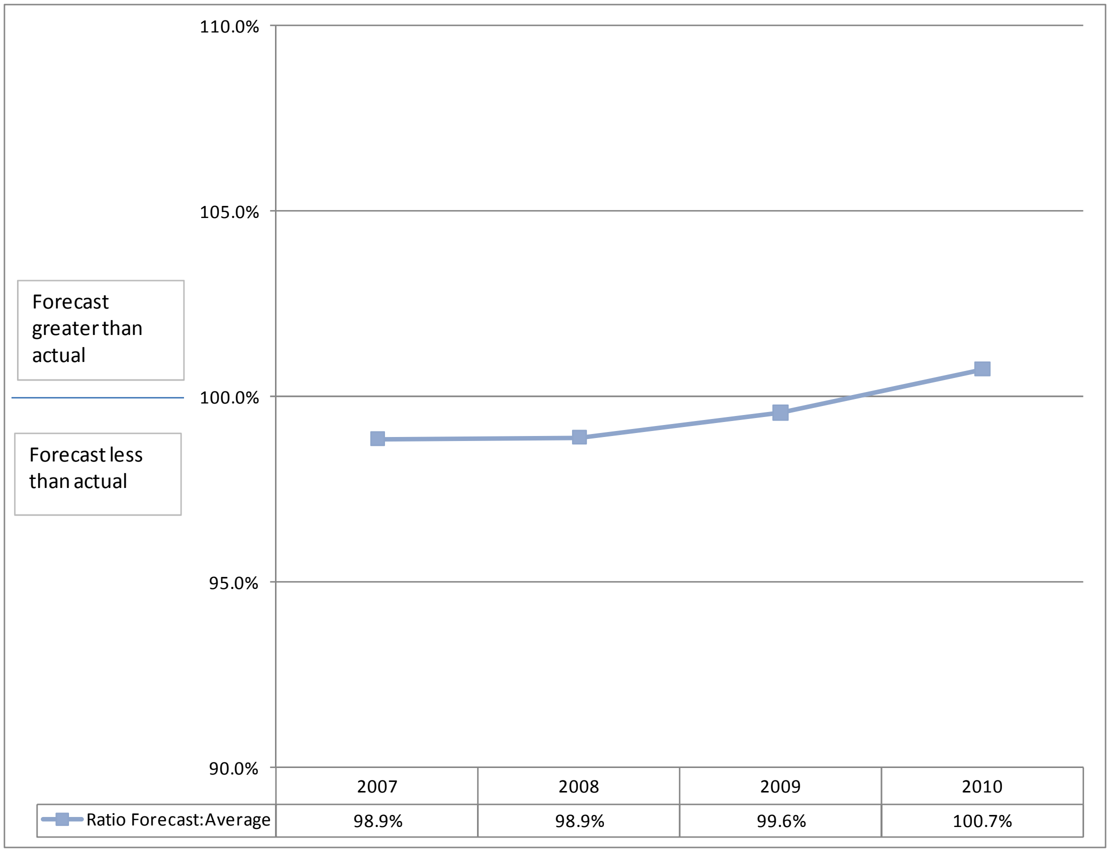
4.3.4 COMMERCIAL CUSTOMER ADDITIONS FORECAST METHODOLOGY

Commercial customer additions and the existing commercial customer totals are the second key input for the commercial demand forecast. The total customer count (including additions) is multiplied by the average use per customer to form the commercial demand forecast. Consistent with prior forecasts, and in the absence of independent third party commercial forecasts, the forecast of Commercial Customer Additions is based upon an analysis of recent trends in each region and Commercial rate class.

This method has provided accurate results in the past as shown in the following figure for Rate Schedules 2, 3 and 23 for the Mainland region. The figure compares the forecast and actual commercial customer totals for 2007, 2008, 2009 and 2010. The points in the figure are the ratio of actual year end commercial account totals compared to the forecast total for the same period. For the purpose of this section only the Mainland region is shown as it accounts for approximately 89 percent of all commercial accounts.

As seen below, the maximum error using this method was 1.1 percent in both 2007 and 2008. The average error for the four year period was 0.5 percent. Given this level of accuracy, trending based on our recent actual customer account data provides a reasonable forecast of customer additions.

Figure 4.3-5: Comparison of Forecast to Actual Commercial Customers, Mainland Region



4.3.5 COMPARISON OF WEATHER VS. CUSTOMER ADDITIONS AS DEMAND DRIVERS

In considering the demand forecast it is helpful to consider the relative weight and importance of the inputs. Our analysis reveals that on average total residential demand is more than five times more sensitive to weather fluctuations than it is to the demand from new customers. Weather, and its annual deviation from ten year normals, plays a substantially bigger role in the annual residential demand than do customer additions. The data and discussion in this section demonstrates the relative impacts of weather and residential account additions as drivers for total residential demand.

In this examination we will consider:

- Annual weather related residential demand variance, comparing actual demand to weather normalized demand for existing customers. This will establish the demand variance related to non-normal weather;

- Demand generated by the net customer additions; and
- A comparison of the demand from the above two sources.

4.3.5.1 Annual Weather Related Residential Demand Variance

Table 4.3-1 below compares normalized to actual total demand for the Residential Rate Schedule 1 for the Lower Mainland sub-region. The table shows that on average the actual demand can be expected to vary by 3.2 PJs per year compared to normalized demand. The 3.2 PJs is a result of non-normal weather. When the difference is close to 0 (i.e. 2005 and 2006) it indicates weather approaching the 10 year normal.

Table 4.3-1: Lower Mainland Actual and Normal Demand

	2003	2004	2005	2006	2007	2008	2009	2010	8-Yr Avg
Actual Demand (PJ)	50.7	48.4	51.1	51.3	56.2	58.8	53.2	48.7	52.3
Normalized Demand (PJ)	54.0	53.9	51.6	52.1	52.7	51.6	52.4	52.6	52.6
Difference (PJ)	-3.3	-5.5	-0.5	-0.8	3.5	7.2	0.8	-3.9	
Absolute value of Difference (PJ)	3.3	5.5	0.5	0.8	3.5	7.2	0.8	3.9	3.2

4.3.5.2 Demand from Net Customer Additions

We can compare the expected 3.2 PJs demand variance from non-normal weather to the demand generated from our net customer additions, as shown in the following tables.

The following table shows the year end accounts and net customer additions from 2003 through 2010.

Table 4.3-2: Lower Mainland Year End Accounts

	2003	2004	2005	2006	2007	2008	2009	2010	8-Yr Avg
Year End Accounts	486,954	494,756	502,589	508,748	516,801	521,437	524,620	529,194	
Account Additions	4,892	7,802	7,833	6,159	8,053	4,636	3,183	4,574	5,892

We can determine the actual UPC from the Actual Demand and the Year End Accounts.

Table 4.3-3: Lower Mainland Actual UPC

	2003	2004	2005	2006	2007	2008	2009	2010	8-Yr Avg
Actual UPC (GJ)	104.1	97.8	101.7	100.8	108.7	112.8	101.4	92.0	102.4

The Actual UPC[66] multiplied by the Account Additions provides the demand from the new customers from 2003 through 2010 as shown in the following table:

Table 4.3-4: Lower Mainland Demand from New Customers

	2003	2004	2005	2006	2007	2008	2009	2010	8-Yr Avg
Demand from new customers (PJ)	0.5	0.8	0.8	0.6	0.9	0.5	0.3	0.4	0.6

4.3.5.3 Comparison of Demand from Non-Normal Weather and Customer Additions

We can now compare the demand from new customers to the demand variance from non-normal weather as shown in the following table.

Table 4.3-5: Lower Mainland Weather Significance

	2003	2004	2005	2006	2007	2008	2009	2010	8-Yr Avg
Demand from new customers (PJ)	0.5	0.8	0.8	0.6	0.9	0.5	0.3	0.4	0.6
Absolute demand from non-normal weather (PJ)	3.3	5.5	0.5	0.8	3.5	7.2	0.8	3.9	3.2
Significance Factor (Weather:Customer Additions)	6.4	7.1	0.7	1.3	4.0	13.8	2.6	9.2	5.3

When the "Significance Factor" is 1.0, the demand from non-normal weather is equal to the demand from new customer additions. This is likely to happen in years where the weather is near normal and the customer additions are above average. An example is 2005.

In years where the weather is "normal" the Significance Factor will be 0.

In years where the weather is significantly different from normal the effect weather has on demand is much greater than the demand generated by customer additions. If the net customer additions are below average the effect is compounded. An example is 2008 where, due to weather much colder than normal, residential demand was 7.2 PJs greater than expected and 13.8 times greater than the demand from the 4,636 new customers added that year.

On average the demand variance from non-normal weather has been 5.3 times greater (530 percent) than the demand from new customers since 2003.

In conclusion total residential demand is more than five times more sensitive to weather fluctuations than it is to the demand from new customers. As a driver for residential demand, customer additions are important but, on average, are dwarfed by the impact of weather on the much larger existing customer base.

66 Annual UPC is used in this example for simplicity. The companies use monthly UPC to calculate demand.

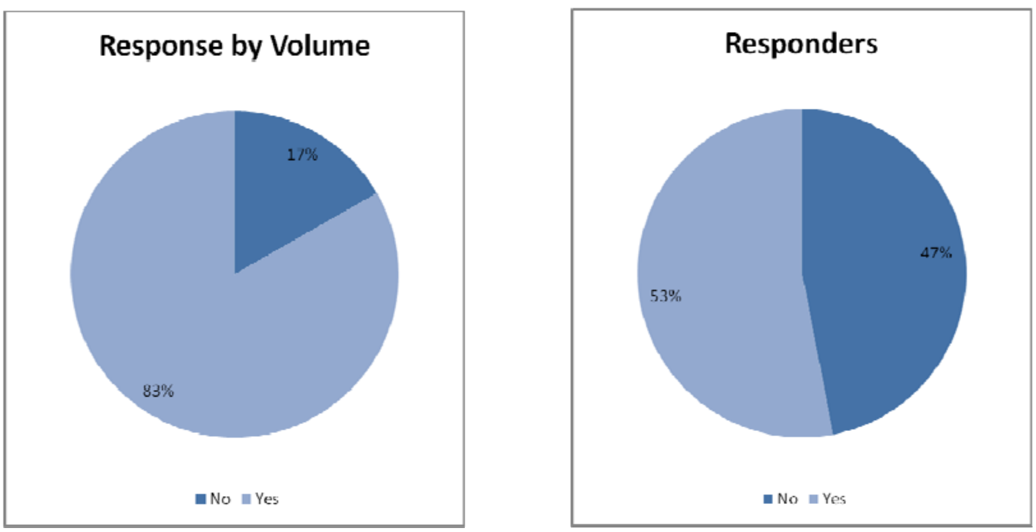
4.3.6 INDUSTRIAL DEMAND FORECAST METHODOLOGY

The forecast of **Industrial Energy Demand**, due to the smaller number of customers in each rate class, is based upon customer specific results from the annual Industrial Demand Survey.

The forecast for **Industrial Customer Additions** assumes no net change in the number of customers over the forecast period except where specific knowledge has been received by the Companies.

The survey asks each industrial customer for their short-term forecast monthly consumption and long-term annual consumption. This data is entered directly into the forecast to produce total demand for each industrial rate schedule. This year the Industrial Demand Survey was sent electronically. The survey was both easier to complete for our customers and easier to process for FEI staff than in the past. The participation rate in the survey increased this year and responses accounted for approximately 83 percent of the Industrial demand.

Figure 4.3-6: Response to 2010 Industrial Survey



We recognize that further improvements can be made to this process. In the future we will investigate the benefits of implementing the following changes:

Table 4.3-6: Potential Survey Improvements

Potential Survey Improvement	Expected Benefit
Internet Based Survey	• Higher participation rates in current Rate Schedules • Include additional Rate Schedules • Reduced staff time for processing results
Compare Forecast to Actual for each Customer	Allow us to make adjustments to specific customer forecasts where a clear trend of over- or under-forecasting has occurred.
Different survey for heat sensitive customers	Determine which Industrial customers are heat sensitive and provide them with a shorter, simpler survey. The survey would ask for process changes but not require the respondent to forecast total monthly consumption.

The table above is not intended as an exhaustive list. These and other changes may be investigated for potential impact, ease and cost of implementation, data security and possibly other factors. In the meantime, the Companies believe that the methodology of surveying industrial customers to forecast industrial demand continues to be reasonable.

4.3.7 REVIEW OF HISTORICAL DATA

Once the independently developed forecast is complete, it is compared with historic normalized data. Through this comparison, the forecast for gas usage by our customers is verified.

Using the forecast software system we are able to directly compare historic actual data alongside the forecast at many different levels (i.e. use per customer, accounts, energy demand etc). The graphical comparison is available at the region, sub-region and rate class level from 2003 through the forecast period. The graphical comparison allows us to establish the reasonableness of the forecast.

4.4 Mainland Demand Forecast and Revenues

4.4.1 INTRODUCTION

This section describes the forecast of average UPC, customer additions and total energy demand over the forecast period for the Mainland region.[67]

In order to forecast the Mainland total energy demand, FEI considers the following:

- Average Use rates by rate class;

[67] The Mainland region presented in this section includes the Lower Mainland, Inland, Columbia and Revelstoke regions.

- Customer Additions; and
- Industrial Demand.

These three inputs together form the basis for the forecast model. The total energy demand resulting from this model is forecast to be relatively stable over the forecast period.

Since 2003, the net increase in Residential customers is approximately 63,000. At the same time, more efficient home and appliance standards have been adopted, and we have experienced a continued shift towards more multi-family dwellings in the housing mix. Overall, the growth in Residential customers has not offset the decline in average Residential UPC, which has resulted in a decline in overall Residential energy demand.

However, increased UPC in selected Commercial and Industrial rate classes is expected to offset this decline in Residential demand resulting in the overall slight increase in total demand for 2012 and 2013.

This section is organized as follows:

- Revenue Stabilization and Adjustment Mechanism
    - Discusses the method by which delivery margins for residential and commercial customers are stabilized
- Residential and Commercial Use Rates
    - Discusses forecast of average use rates for each rate schedule
- Customer Additions
    - Discusses forecast of net residential and commercial customer additions
- Demand Forecast
    - Discusses total energy demand for all residential, commercial and industrial rate schedules
- Revenue and Margin Forecast
    - Monetization of demand

4.4.2 REVENUE STABILIZATION ADJUSTMENT MECHANISM

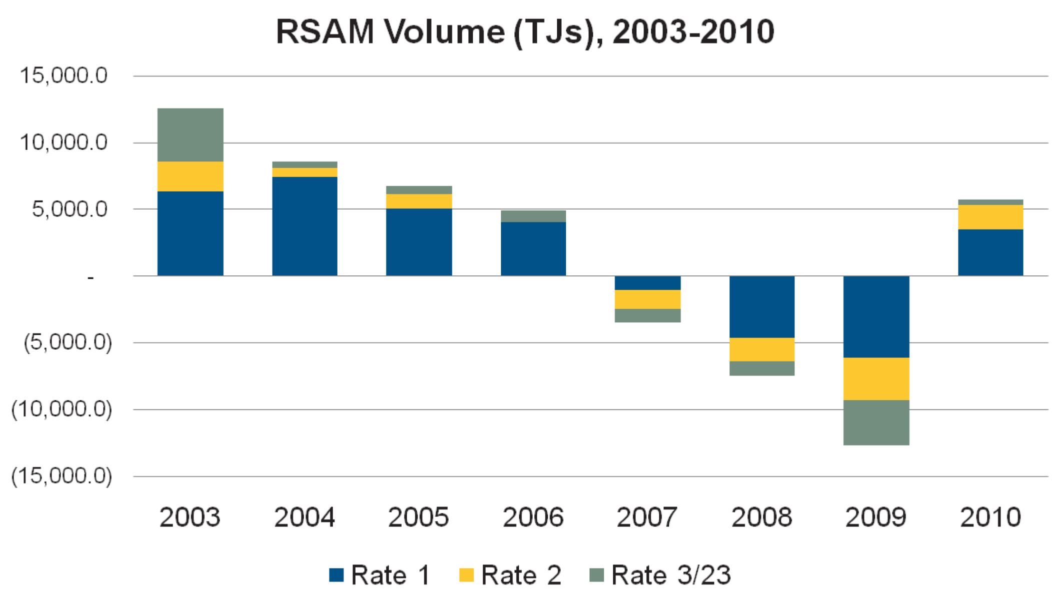
Mainland utilizes an RSAM which stabilizes the margins recovered from Mainland Residential and Commercial customers.[68]

The RSAM stabilizes delivery margin received from Residential and Commercial customer classes on a UPC basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, Mainland records the delivery charge differences in the RSAM deferral account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years.

Having an RSAM mechanism does not offer Mainland protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as Industrial customers.

As shown in the following Figure 4.4-1, demand for Rate Schedules covered by RSAM in the Mainland region can vary by +/- 12 PJs in a particular year. Negative volumes indicate below normal temperatures.

Figure 4.4-1: RSAM Volumes Since 2003



The RSAM captures variances that occur in forecast to actual for factors such as weather that cannot be forecast with any degree of certainty.

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68 Mainland Rate Schedules 1, 1U, 1X, 2, 2U, 2X, 3, 3U, 3X and 23

4.4.3 RESIDENTIAL AND COMMERCIAL USE RATES

Individual average UPC forecasts are developed for each service area and for each residential and commercial customer class. The analysis of historic normalized **residential** use rates indicates a continued downward trend, while normalized **commercial** average use rates are proving to be more stable.

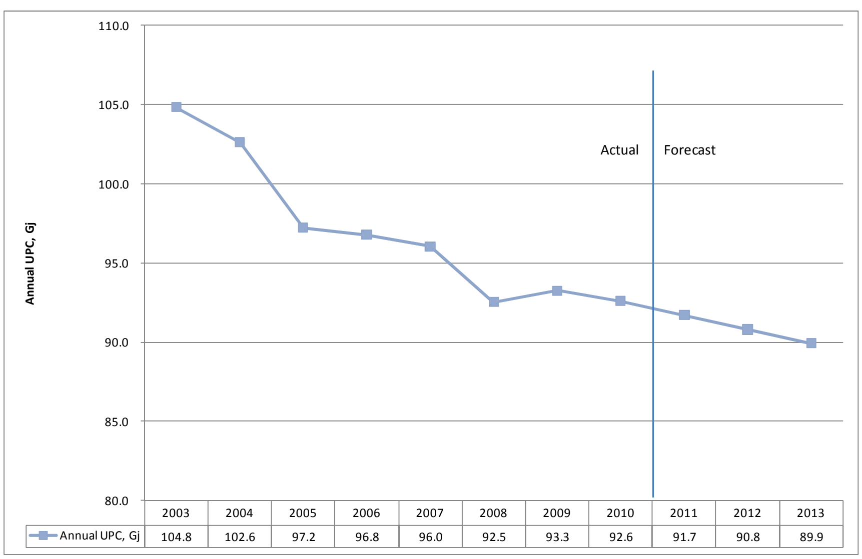
Customer migration, in the commercial customer classes, also affects the average UPC. Customers with annual consumption that falls outside the consumption range specified under their current rate class can skew the average UPC for the entire customer class. Consumption for this group of customers is reviewed annually to determine whether or not there will be an impact to average UPC, and if there is, to what extent.

For short term forecasts such as this one prepared for the RRA it is important to review historical consumption levels, as it is through this process that the Company is able to verify trends in the market, and more importantly, determine whether or not those trends are likely to continue into the future. Long term forecasts, such as those prepared for the Long Term Resource Plan, must consider these and other inputs because the recent history is not always an accurate or complete predictor of long term trends. Developing the inputs for the Long Term Resource Plan is substantially more difficult due to the number of factors that must be considered.

As can be seen from the figures in this section, the forecast of average UPC for Residential and Commercial rate classes is consistent with the trend of historical values.

As shown below, the Residential UPC is forecast to continue downward. For the Mainland region the decline is forecast to continue at approximately 0.9 GJ per year.

Figure 4.4-2: Mainland - Rate Schedule 1 UPC Declining Consistent with Prior Years



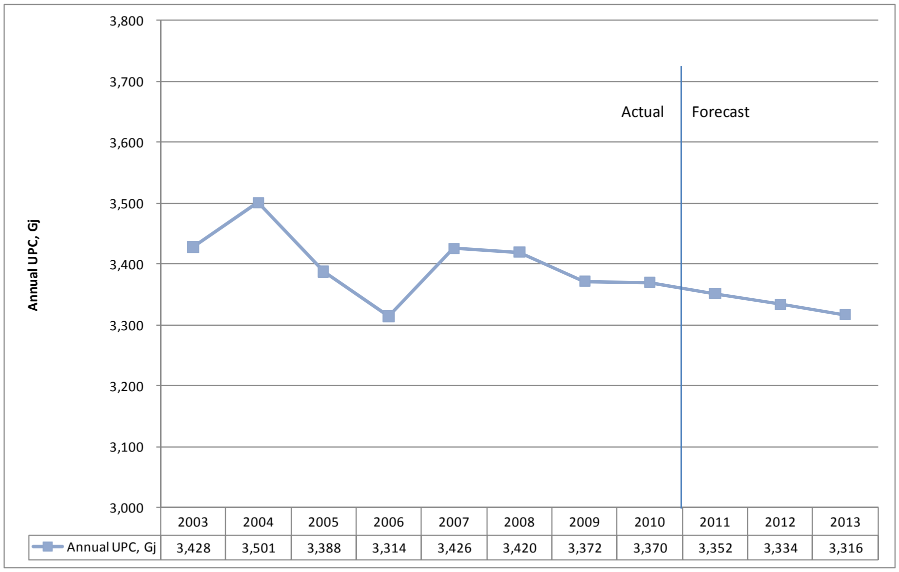
As seen below, the Rate Schedule 2 UPC in the Mainland region is forecast to decline slightly during the forecast period. The annual UPC reduction is forecast to be 1.6 GJ per year or approximately 0.5 percent.

Figure 4.4-3: Mainland - Rate Schedule 2 UPC Consistent with Prior Years

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Annual UPC, Gj	321.2	313.8	305.8	314.3	316.5	312.2	320.6	311.3	309.6	308.0	306.4

As seen below, the decline in Rate Schedule 3 UPC for the Mainland region has been consistent and this trend is forecast to continue. The annual decline in the Rate Schedule 3 UPC is forecast to be 17.4 GJ or approximately 0.5 percent.

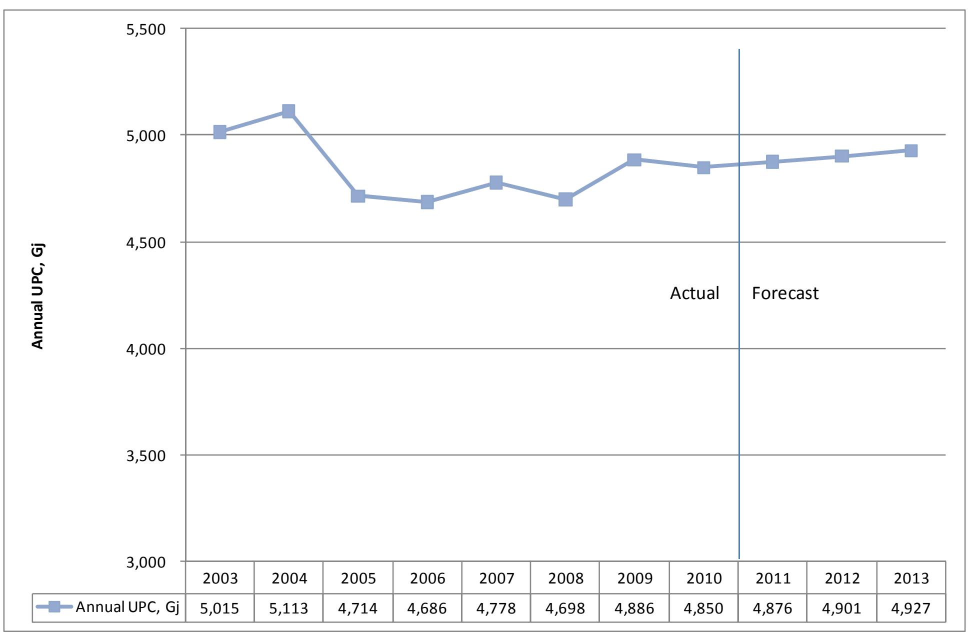
Figure 4.4-4: Mainland - Rate Schedule 3 UPC Consistent with Prior Years



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Annual UPC, Gj	3,428	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,352	3,334	3,316

As seen below, the Mainland Rate Schedule 23 UPC is forecast to continue the slight recent upward trend.

Figure 4.4-5: Mainland - Rate Schedule 23 UPC Slight Recent Upward Trend

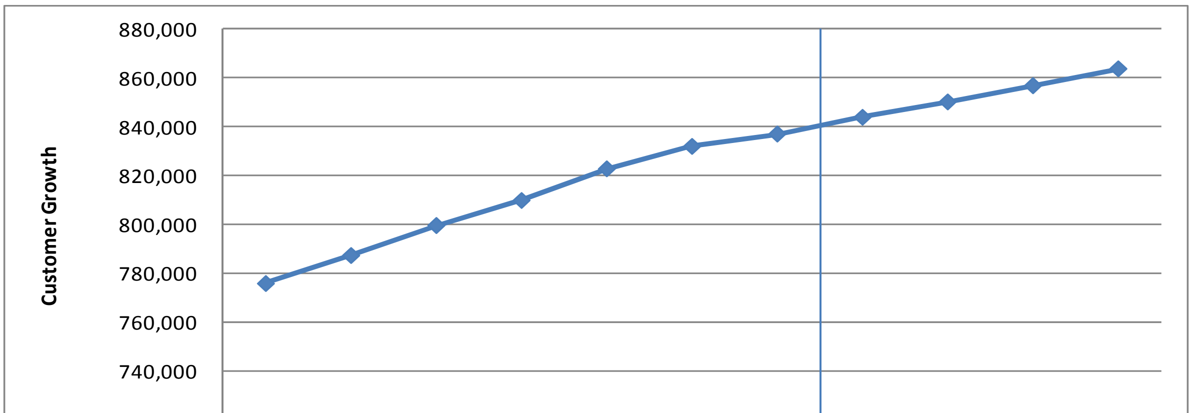


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Annual UPC, Gj	5,015	5,113	4,714	4,686	4,778	4,698	4,886	4,850	4,876	4,901	4,927

4.4.4 CUSTOMER ADDITIONS

The rate of growth seen in our customer base reached a high in 2007 of roughly 12,000 customers but declined in 2008 and 2009. In 2010 account additions rebounded and the Company added just over 6,900 customers in the Mainland region.

Figure 4.4-6: Mainland - Total Customer Growth for all Rate Classes Consistent with Prior Years



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
All Rate Classes	775,603	787,123	799,427	809,718	822,687	831,886	836,976	843,845	850,159	856,815	863,738

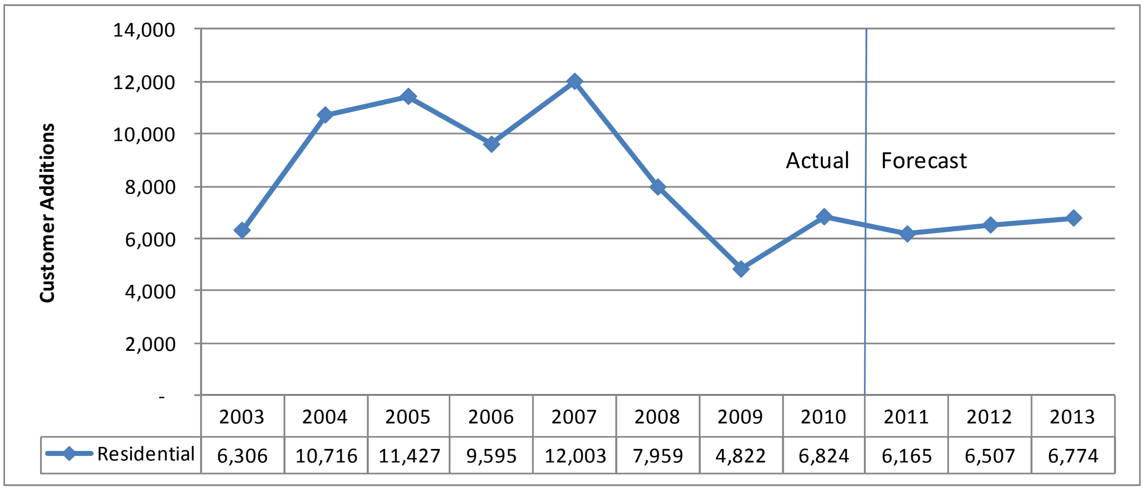
The forecast of customer additions is based on the CMHC's and the CBOC's Residential forecast, which is consistent with prior years. Customer additions are forecast for both Residential and Commercial customer classes.

The Residential forecast was reviewed for consistency with our historic customer additions and was then reviewed internally by the Residential and Commercial Energy Solutions group (part of the Energy Solutions and External Relations department). Residential and Commercial Energy Solutions staff made adjustments based on their in depth knowledge of their service areas.

No growth in customer additions was assumed for Industrial customers in Rate Schedules 5, 22, 25, and 27 as none were known of at the time of the forecast. It should be noted, that the forecast demand in Section 4.4 for FEI does not include new customer additions or energy demand for CNG and LNG service that is presented in Section 5.5.5 and Appendix I.

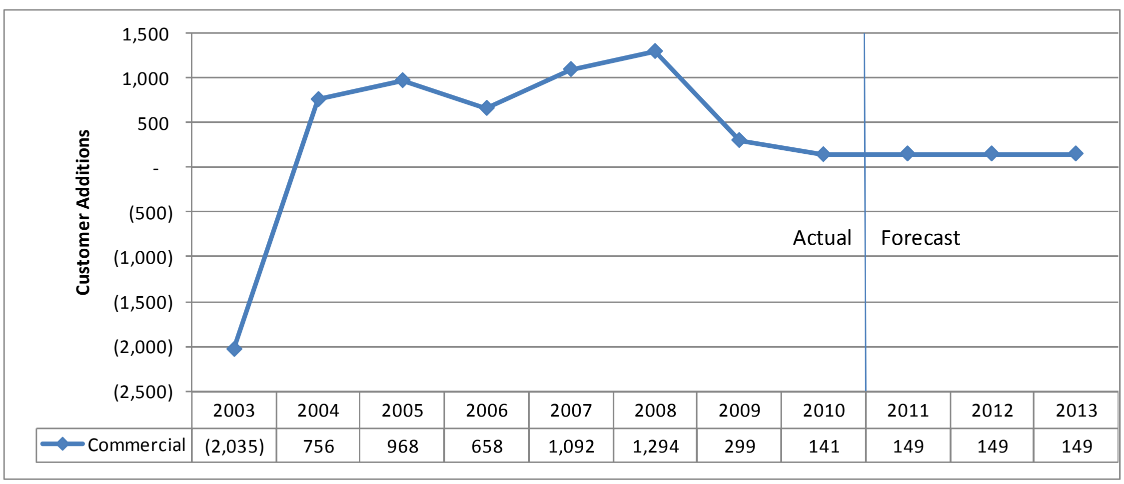
The following Figures (Figures 4.4-7 and 4.4-8) provide a summary of the Residential and Commercial net customer additions projected for 2011, and the forecast for the years 2012 and 2013.

Figure 4.4-7: Mainland - Residential Customer Additions



As shown in the preceding figure, Residential net additions rebounded in 2010 from the lows observed in 2009. Additions in 2011 are forecast to be slightly lower than 2010 and then will gradually increase in 2012 and 2013.

Figure 4.4-8: Mainland - Forecast Commercial Customers Additions

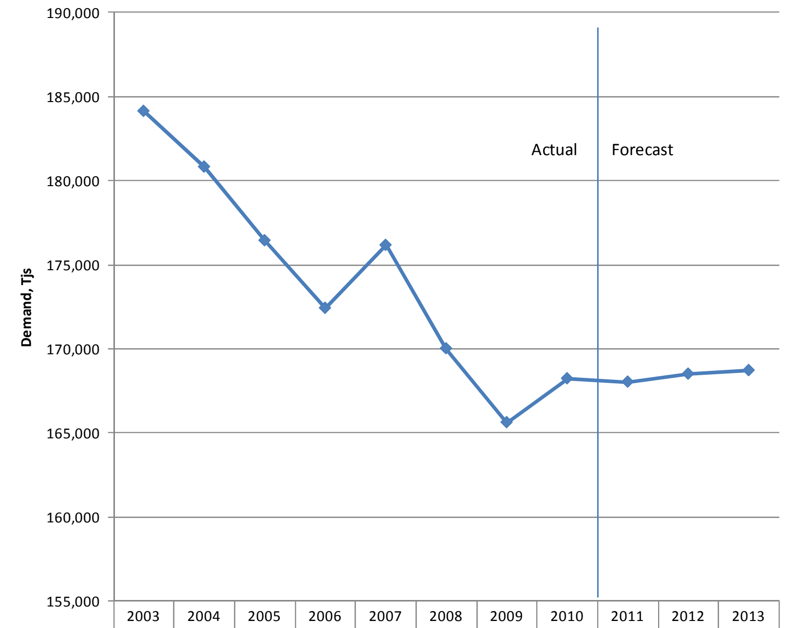


The net Commercial customer additions have historically been very volatile. Commercial net customer additions declined dramatically in 2009 and moderately in 2010. Based on the lack of a clear trend and through interviews with internal staff we are forecasting a modest 149 additions per year for the forecast period.

4.4.5 DEMAND FORECAST

As seen below in Figure 4.4-9, the total normalized demand for the Mainland region is projected to be approximately 168 PJs in 2011, in line with 2010 actuals. For 2012 and 2013 the total normalized demand is forecast to be slightly higher as a result of increases in Commercial and Industrial rate classes.

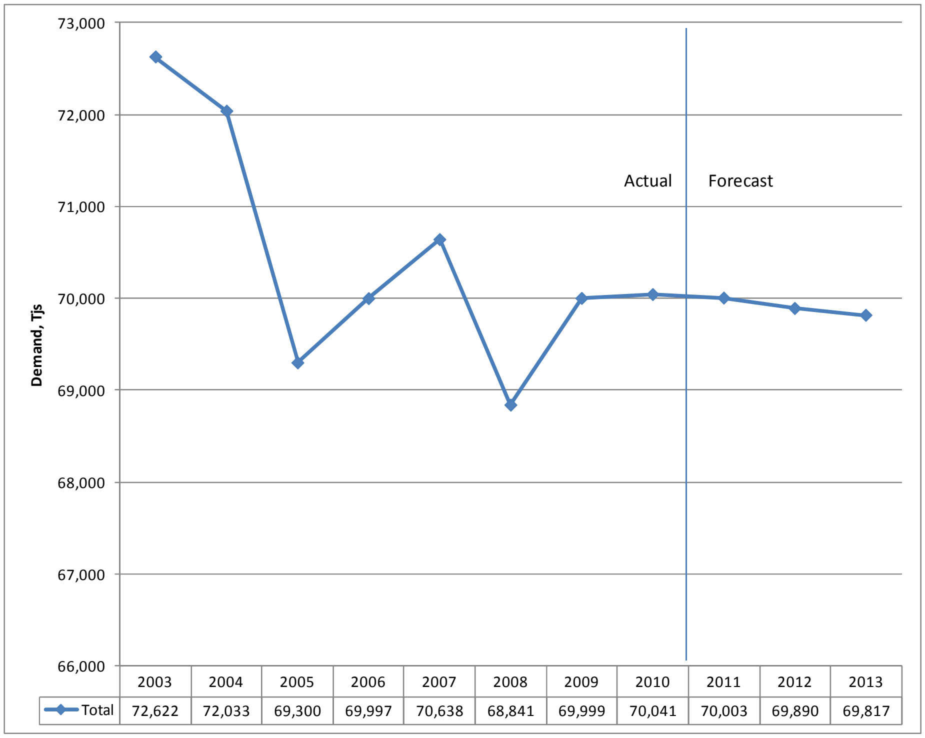
Figure 4.4-9: Mainland - Total Normalized Energy Demand in TJs



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total	184,134	180,817	176,431	172,410	176,160	170,007	165,607	168,222	168,019	168,496	168,707

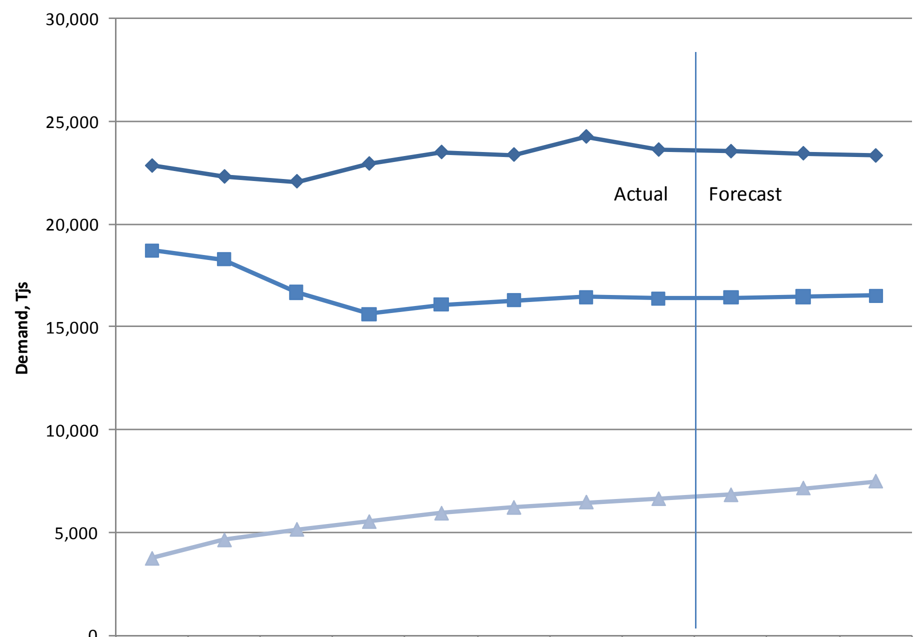
As shown below in Figure 4.4-10, the growth in Residential customers has not offset the decline in average Residential UPC, which has resulted in an overall decline in Residential normalized energy demand.

Figure 4.4-10: Mainland - Normalized Residential Demand



As seen in the Figure 4.4-11 below, increased UPC in Rate Schedule 23 Commercial Transportation Service is expected to result in a slight increase in overall Commercial demand.

Figure 4.4-11: Mainland - Commercial Demand



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
RATE2	22,837	22,304	22,071	22,942	23,503	23,377	24,261	23,619	23,545	23,438	23,332
RATE3	18,732	18,295	16,671	15,637	16,078	16,291	16,455	16,394	16,423	16,469	16,515
RATE23	3,724	4,621	5,139	5,516	5,927	6,207	6,469	6,630	6,822	7,152	7,485

As seen below the demand from the Industrial rate classes is forecast to stabilize close to 2010 levels based on responses to the 2010 Annual Industrial Survey. In the forecast, demand for Industrial customers that did not participate in the annual survey was held constant at 2010 levels.

Figure 4.4-12: Mainland - Industrial Demand

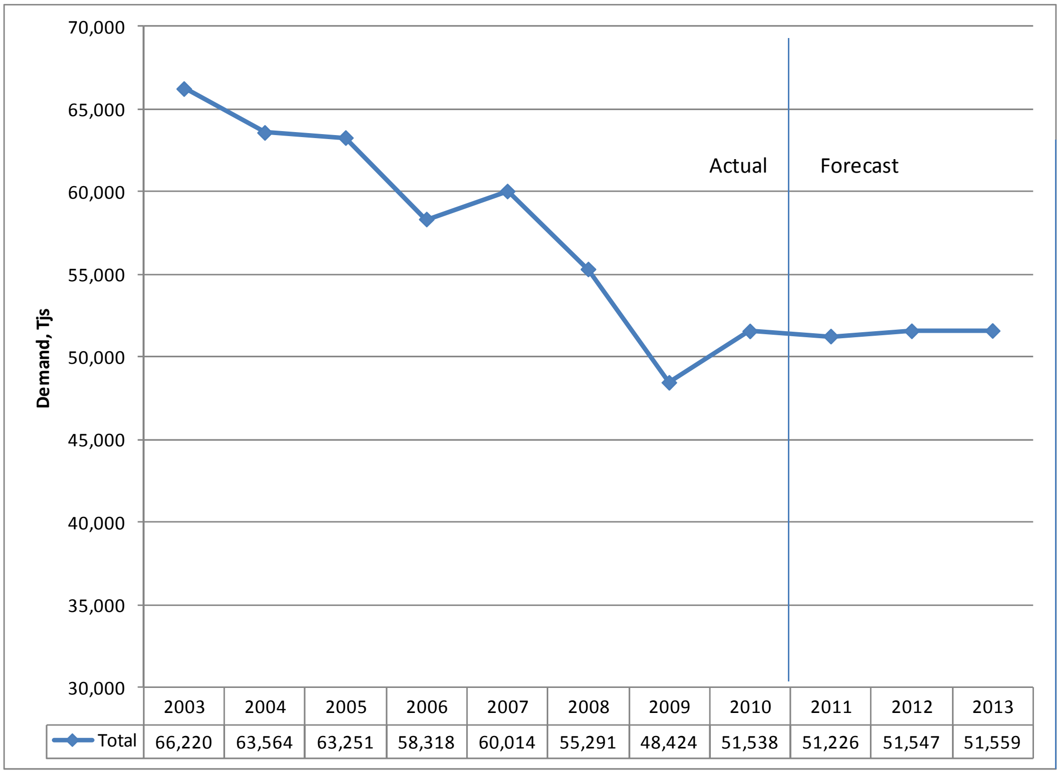


Table 4.4-1 outlines the total demand for Mainland by residential, commercial, and industrial sectors for 2012 and 2013.

Table 4.4-1: Mainland – Demand

Energy (Tjs)	2012	2013
Mainland		
Residential	69,890	69,817
Commercial	47,059	47,332
Industrial	51,547	51,559
Grand Total	**168,496**	**168,707**

4.4.6 MAINLAND REVENUE AND MARGIN FORECAST

A reasonable forecast of revenues and margins has been developed by considering the total energy forecast applied at existing 2011 approved rates.

4.4.6.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEI has developed a reasonable forecast of revenues by applying the total energy forecast to the currently approved rates (as at January 1, 2011) for each customer class.

The revenue forecast presented in Table 4.4-3 does not include amounts for Vancouver Island Wheeling and B.C. Hydro for Burrard Thermal. The Burrard Thermal revenues are included in the financial schedule in Section 7.1, Schedules 11 and 12 of the Application. The Vancouver Island Wheeling revenues are included in the financial schedule in Section 7.2, Schedules 19 and 20 of the Application. Both revenues reflect existing contractual revenue and volume agreements.

Table 4.4-2 below summarizes the revenues projected for 2011 and forecast for 2012 and 2013, at 2011 rates.

Table 4.4-2: Forecast Sales Revenue for Mainland

Revenue ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Mainland			
Residential[1]	750.2	750.0	750.3
Commercial[2]	382.2	382.6	383.1
Industrial[3]	73.0	73.5	73.6
Grand Total	**1,205.3**	**1,206.1**	**1,207.0**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 23
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

4.4.6.2 Margin

Margins are a function of both total revenues and the cost of natural gas being provided to customers. The Company has developed a reasonable forecast of margins by first developing the forecast of revenues at existing approved rates and then subtracting from that the cost of natural gas.

Table 4.4-3 below summarizes the margin projected for 2011 and forecast for 2012 and 2013, by customer segment, at 2011 approved rates

Table 4.4-3: Forecast Gross Margin for Mainland

Margin ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Mainland			
Residential[1]	336.4	336.9	337.6
Commercial[2]	150.5	151.4	152.2
Industrial[3]	58.0	58.9	59.0
Grand Total	**544.9**	**547.2**	**548.8**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 23
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

Revenues are comprised of both fixed and variable charges, and the portion each contributes to the margin varies for each customer segment. The revenues for the Residential and Commercial customer segments have a smaller portion of fixed to variable charges (approximately 20 percent fixed, 80 percent variable) than do the firm sales and Industrial customer segments, where approximately 55 percent of revenues are fixed compared to 45 percent variable. This means that the margin collected for Residential and Commercial customers is more influenced by annual fluctuations in consumption patterns than it is for firm sales and Industrial customers. Similarly, margins collected from firm sales and Industrial customers, due to the nature of their contracts, are partially protected from yearly fluctuations in usage patterns.

4.4.7 SUMMARY

Through considering the factors influencing customer additions, average UPC and also Industrial volumes the Company has developed a forecast of demand for natural gas. The economic turmoil and dramatic decline seen recently has subsided and the housing starts are returning towards traditional levels. Customers continue to look for ways in which to improve efficiencies and as a result average UPC will also continue to decline over the forecast period. The Industrial survey analyses indicated that overall Industrial volumes will increase slightly in the near future. It is through considering these factors, applying a methodology consistent with prior years, and by using the latest and best information available that the Company believes it has developed a reasonable demand forecast that is the most appropriate to be used in the determination of rates for the 2012 and 2013 forecast period.

4.5 Vancouver Island Demand Forecast

4.5.1 INTRODUCTION

This section describes the forecast of average UPC, customer additions and total energy demand over the forecast period for the Vancouver Island region.

In order to forecast the Vancouver Island total energy demand FEVI considers the following:

- Average Use rates by rate class;
- Customer Additions;
- Industrial Demand;

These three inputs together form the basis for the forecast model. Following an increase in 2011 the total energy demand for Vancouver Island is forecast to stabilize for the remainder of the forecast period.

This section is organized as follows:

- Rate Stabilization Deferral Account
  - Discusses the method by which delivery margins for residential and commercial customers are stabilized
- Residential and Commercial Use Rates
  - Discusses forecast of average use rates for each rate schedule
- Customer Additions
  - Discusses forecast of net residential and commercial customer additions
- Demand Forecast
  - Discusses total energy demand for all residential, commercial and industrial rate schedules
- Revenue and Margin Forecast

4.5.2 RATE STABILIZATION DEFERRAL ACCOUNT

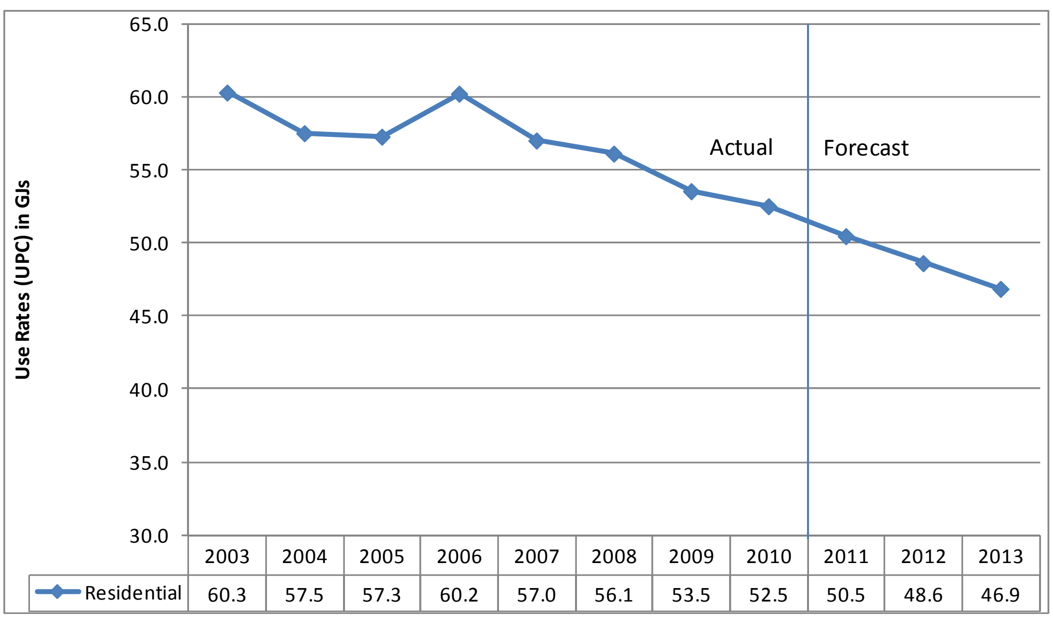
In the 2010-2011 RRA for Vancouver Island, we developed and received approval for an interim rate mitigation strategy, to offset the rate pressure resulting from the loss of the royalty revenues on Vancouver Island at the end of 2011. This interim strategy resulted in a rate freeze for core market customers and the creation of an RSDA, to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast. The RSDA captures the volume variance due to the Vancouver Island's forecast volumes versus actual volumes and is similar to Mainland's RSAM in this respect.

4.5.3 RESIDENTIAL AND COMMERCIAL USE RATES

The average UPC forecast is the first component of determining the total demand for natural gas. Individual average UPC projections are developed for each of the core market (Residential and Commercial) customer classes.

Since 2006 the Residential General Service Rate No. 1 ("RGS-1") UPC has declined by almost 2 percent per year. This trend is forecast to continue for the duration of the forecast period. This is illustrated in Figure 4.5-1 below.

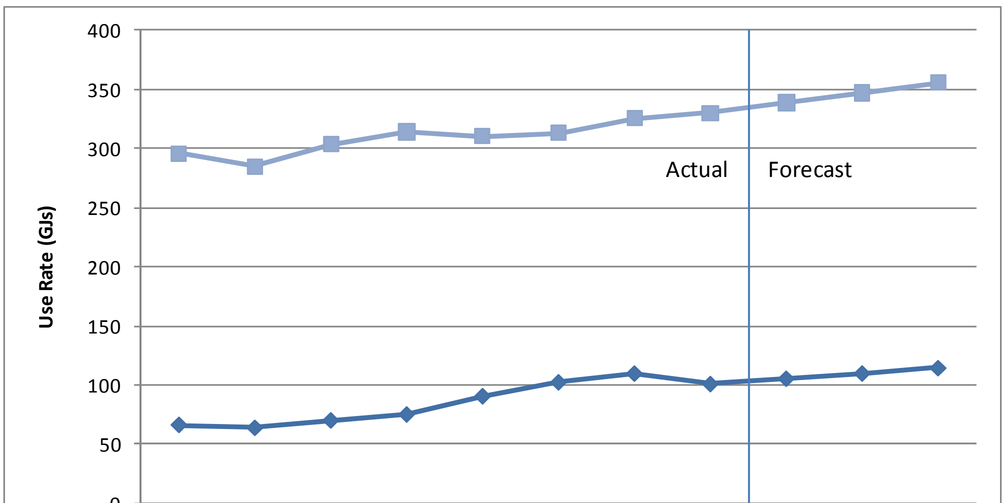
Figure 4.5-1: Vancouver Island – Residential General Service UPC Trend Continues to Decline



The FEVI believe that the factors influencing this decline in average UPC include the retrofit of appliances, the changing housing mix, and government policies and programs aimed at improving efficiencies. These factors are likely to continue to influence UPC in the coming years, consistent with the forecast decline for 2012 and 2013. It is also important to review historical consumption levels, as it is through this process that Vancouver Island is able to validate trends in the market, and more importantly, determine whether or not those trends are likely to continue into the future.

The average UPC for both the Small Commercial Service Rate No. 1 ("SCS-1") and Small Commercial Service Rate No. 2 ("SCS-2") rate classes are forecast to continue the upward trend observed since 2003. Despite the reduction in UPC in 2010 the SCS-1 rate class is forecast to be back to 110 GJ/yr in 2012 and then increase to 115 GJ/yr in 2013. The SCS-2 rate class is expected to increase by 8 GJ/yr through the forecast period. This is illustrated in Figure 4.5-2 below.

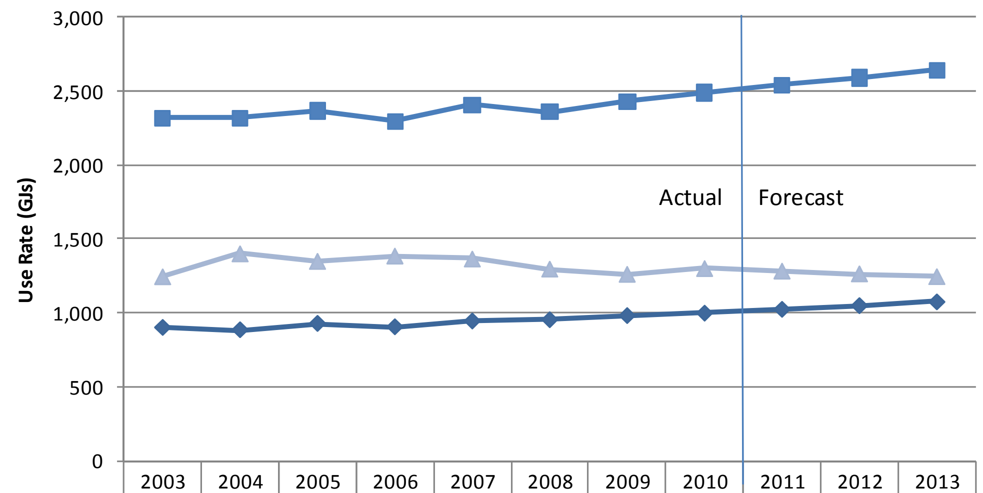
Figure 4.5-2: Vancouver Island – Small Commercial Service Rate No. 1 and Small Commercial Service Rate No. 2 UPC Trend is Consistent with Prior Years



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SCS1	66	64	70	75	91	103	110	101	106	110	115
SCS2	296	285	303	314	310	313	325	330	339	347	355

The UPC in the Large Commercial Service Rate Schedule No. 1 ("LCS-1") and Large Commercial Service Rate Schedule No. 2 ("LCS-2") rate classes are expected to increase gradually for the duration of the forecast period. The Apartment General Service Rate ("AGS") rate class is expected to continue the gradual downward trend of approximately 2 percent per year observed since 2005. This is illustrated in Figure 4.5-3 below.

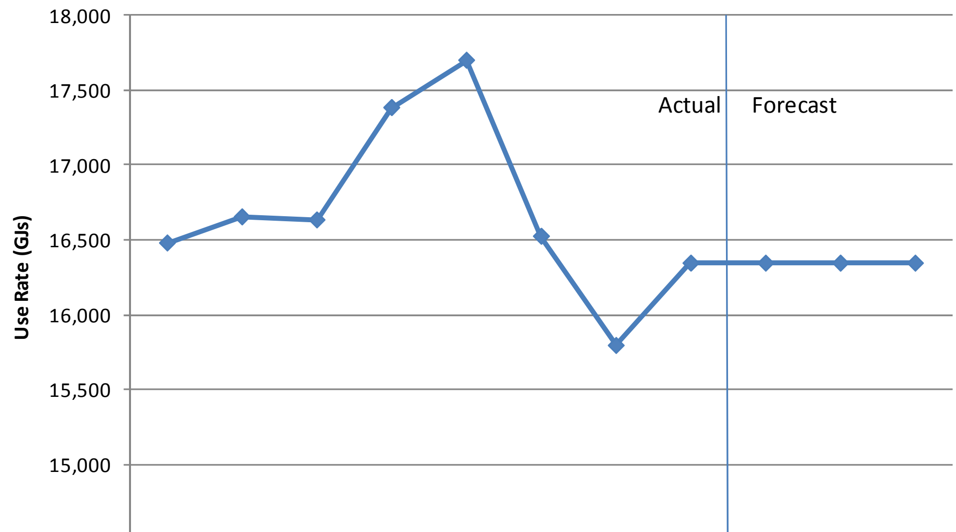
Figure 4.5-3: Vancouver Island – Large Commercial Service Rate Schedule No. 1, Large Commercial Service Rate Schedule 2 and Apartment General Service Rate UPC Trend Consistent with Prior Years



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LCS1	898	883	926	903	943	952	980	997	1,023	1,049	1,075
LCS2	2,319	2,318	2,365	2,295	2,406	2,359	2,430	2,490	2,542	2,591	2,641
AGS	1,244	1,402	1,350	1,387	1,367	1,297	1,261	1,301	1,283	1,264	1,245

The LCS-3 rate class experienced two years of sharply declining use rates during the recent recession. The use rate rebounded in 2010. In the absence of a clear trend, the UPC for LCS-3 is forecast to remain constant for the duration of the forecast period. This is illustrated in Figure 4.5-4 below.

Figure 4.5-4: Vancouver Island – Large Commercial Service Rate Schedule No. 3 UPC Trend is Forecast to Remain Constant



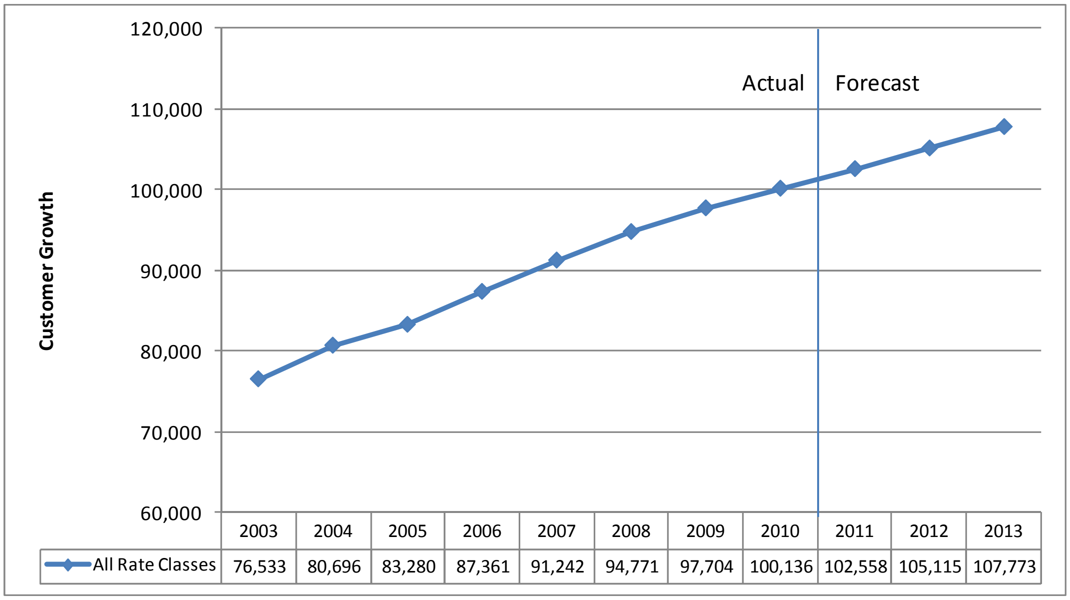
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LCS3	16,476	16,650	16,630	17,379	17,694	16,521	15,793	16,342	16,342	16,342	16,342

4.5.4 CUSTOMER ADDITIONS

The forecast of customer additions is the second component for determining the total energy demand. As in prior years, the forecast of customer additions is based upon the CMHC and the CBOC housing starts forecast, which is reasonable in light of the correlation between housing starts and customer additions.

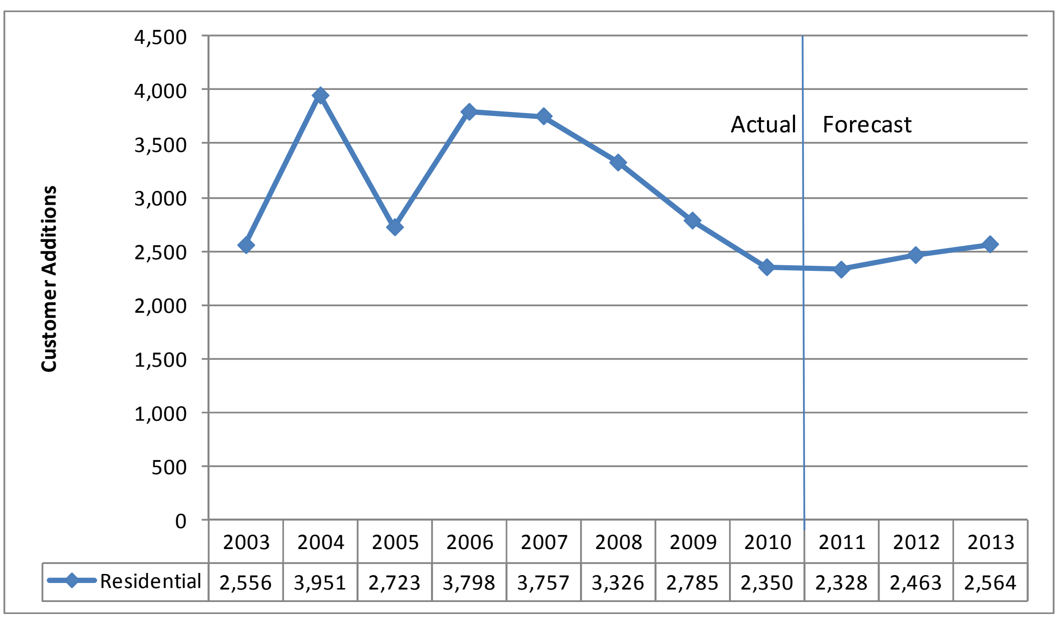
The total customer base on Vancouver Island has increased steadily from just over 76,500 customers in 2003 to in excess of 100,000 customers in 2010. As shown in the above figure the net additions each year are consistent and have averaged approximately 3,250 additions per year since 2004. Based on our account additions methodology FEVI is forecasting a net addition of approximately 2,600 customers per year in 2012 and 2013. This is illustrated in Figure 4.5-5 below.

Figure 4.5-5: Vancouver Island - Total Customer Growth for all Rate Classes Consistent with Prior Years



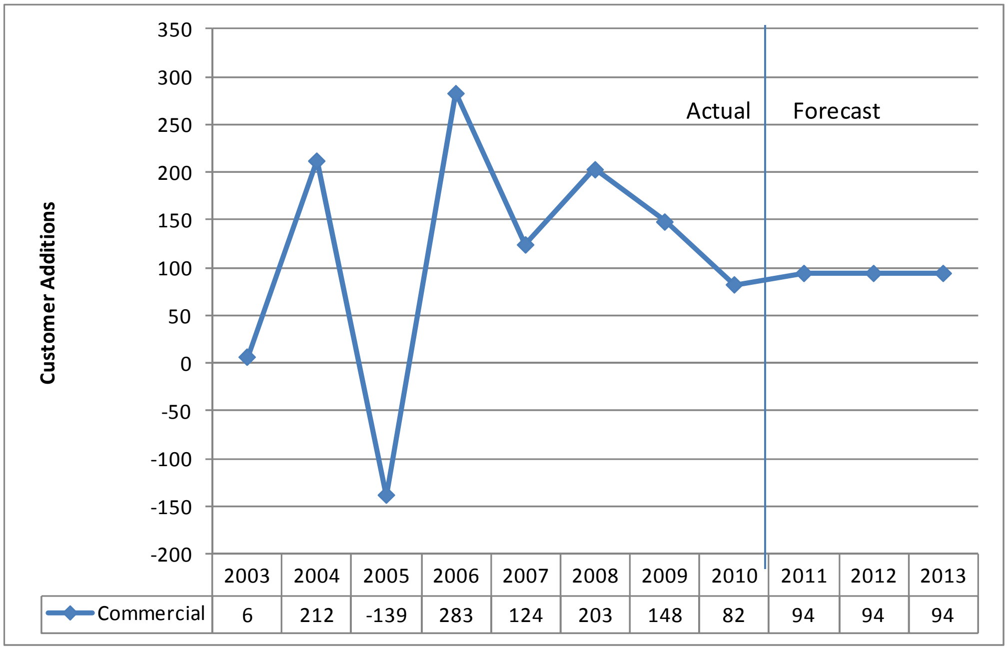
The rate of net Residential customer additions has declined in recent years due in large part to the recent recession. CMHC and CBOC are forecasting an increase in housing starts and this is reflected in our increased forecast of customer additions. This is illustrated in Figure 4.5-6 below.

Figure 4.5-6: Vancouver Island - Residential Customer Additions



The net Commercial customer additions have historically been very volatile. In 2009 and 2010 net Commercial customer additions declined but the rate of decline was not as pronounced as seen in prior years. Based on the lack of a clear trend and through internal interviews we are forecasting a modest 94 additions per year for the forecast period. This is illustrated in Figure 4.5-7 below.

Figure 4.5-7: Vancouver Island - Commercial Customer Additions

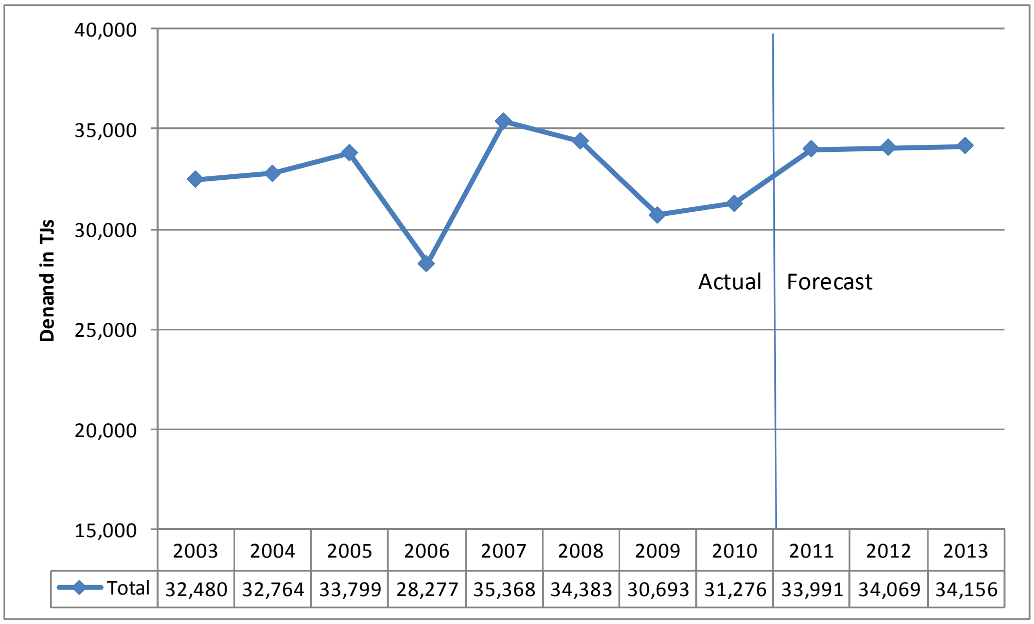


4.5.5 DEMAND FORECAST

As discussed previously, the energy demand forecast for Residential and Commercial customers is derived by applying the total forecast customers, including customer additions, to the average UPC forecast. Then, by adding the forecast energy demand for Transportation customers, based on contractual arrangements at the time of the forecast, the total energy forecast for all rate classes is developed. The total energy forecast is provided below.

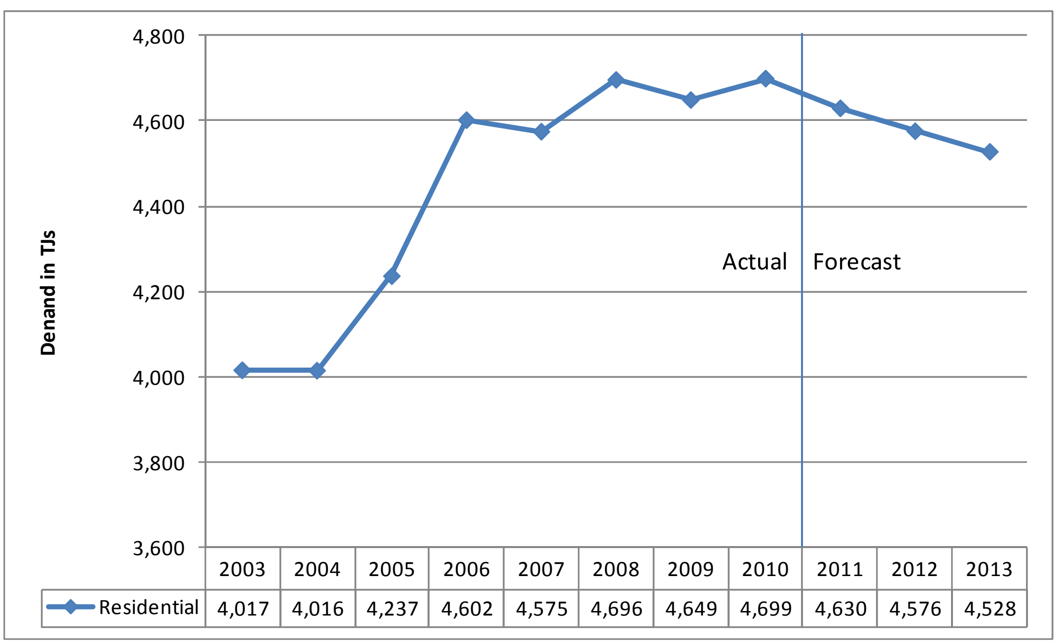
As discussed in the introduction to this section, actual 2010 Transportation demand was less than the 2011 confirmed Contract Demand volumes, resulting in the increase seen in Figure 4.5-8 below. This increase is not offset by the reduction in Residential and Commercial demand. For the forecast period the total energy demand for all customer classes is expected to remain relatively stable. The total energy forecast, for each customer class, is reasonable, based on a methodology that is consistent with prior years, and is appropriate for use in this RRA.

Figure 4.5-8: Vancouver Island – Total Energy Demand



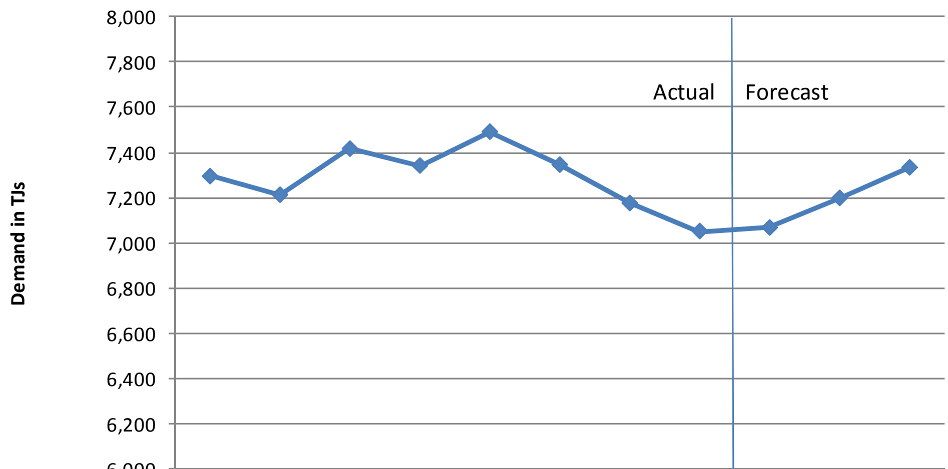
The modest customer additions are not substantial enough to offset the declining UPC. As a result the forecast Residential demand is declining throughout the forecast period. The annual decline during the forecast period is approximately 1.2 percent per year as shown below in Figure 4.5-9.

Figure 4.5-9: Vancouver Island - Residential Demand– Customer Rate Class RGS



As shown in Figure 4.5-10 below, the Commercial demand is expected to increase as a result of the forecast increase in UPC in all Commercial rate classes except AGS.

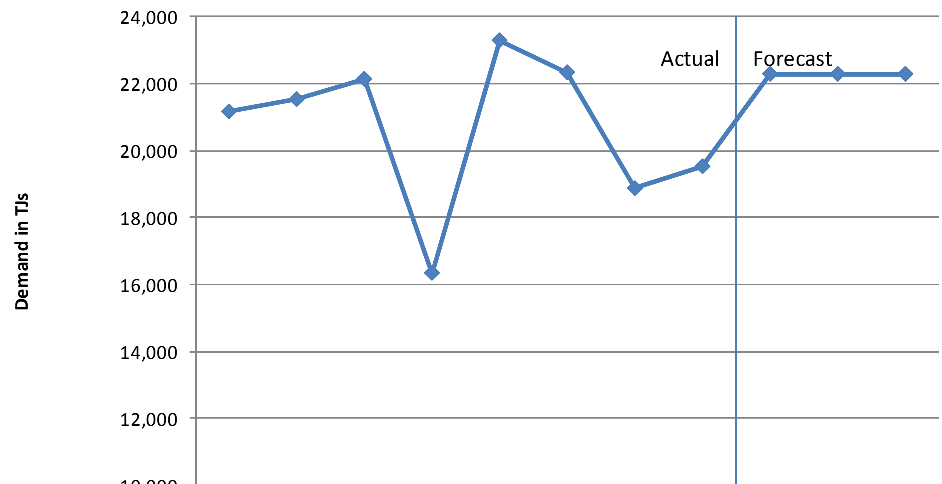
Figure 4.5-10: Vancouver Island - Commercial Demand– All Rate Classes



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Commercial	7,294	7,212	7,416	7,341	7,491	7,345	7,175	7,051	7,066	7,198	7,333

The Transportation demand is forecast to be 22,295 TJs in 2011 and to then remain constant for the duration of the forecast period. Figure 4.5-11 below shows the actual and forecast volumes for 2003 through 2013 for the four transport customers. Two of the four customers have established demand contracts and consistent with past practices we have used their contract demand for 2011 through 2013 forecast. The forecast for British Columbia Hydro and Power Authority ("BC Hydro") is based on 45 TJ/Day for both 2012 and 2013.

Figure 4.5-11: Vancouver Island - Transportation Demand



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Transportation	21,169	21,536	22,146	16,334	23,302	22,342	18,869	19,526	22,295	22,295	22,295

4.5.6 VANCOUVER ISLAND REVENUE AND MARGIN FORECAST

4.5.6.1 Revenue

A reasonable forecast of revenues has been developed by applying the total energy forecast to the currently applicable rates for each customer class. Transportation revenues are based on the appropriate Transportation Service Agreement. Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed.

Table 4.5-1 below summarizes the revenues projected for 2011 and forecast for 2012 and 2013, based on the currently approved rates and Transportation Service Agreement's in place at the time of the forecast.

Table 4.5-1: Forecast Sales Revenue for Vancouver Island

Revenue ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Vancouver Island			
Residential[1]	77.5	77.0	76.7
Commercial[2]	95.4	97.3	99.3
Industrial[3]	20.7	20.7	20.7
Grand Total	**193.6**	**195.1**	**196.6**

Notes:
1. RGS
2. AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, HLF, ILF
3. Transportation

4.5.6.2 Margin

Margins are a function of both total revenues and the cost of natural gas being provided to customers. The Company has developed a reasonable forecast of margins by first developing the forecast of revenues at existing approved rates and then subtracting from that the cost of natural gas.

Table 4.5-2 below summarizes the margin projected for 2011 and forecast for 2012 and 2013, by customer segment, at 2011 approved rates

Table 4.5-2: Forecast Gross Margin for FEVI

Margin ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Vancouver Island			
Residential[1]	51.1	48.1	47.5
Commercial[2]	55.1	51.9	52.0
Industrial[3]	20.7	20.7	20.7
Grand Total	**126.9**	**120.7**	**120.2**

Notes:
1. RGS
2. AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, HLF, ILF
3. Transportation

4.5.7 SUMMARY

Through considering the factors influencing customer additions, average UPC, and Transportation volumes, the Company has developed a forecast of demand for natural gas. The economic turmoil and declines seen recently have subsided and housing starts are returning to traditional levels. During the forecast period an increase in Commercial demand for the forecast period is expected to offset a decline in Residential demand resulting in a slight increase of total demand. It is through considering those factors influencing natural gas consumption, applying a methodology consistent with prior years, and by using the latest and best information available that the Company believes it has developed a reasonable demand forecast that is the most appropriate to be used in this RRA.

4.6 Whistler Demand Forecast and Revenues

4.6.1 INTRODUCTION

This section describes the forecast of average UPC, customer additions and total energy demand over the forecast period for the Whistler region.

In order to forecast the Whistler total energy demand FEW considers the following:

- Average Use rates by rate class; and
- Customer Additions.

These two inputs together form the basis for the forecast model. A modest increase in customers coupled with a 2 GJ increase in Residential UPC is forecast to result in an increased Residential demand for Whistler. This increase is expected to be offset by a decrease in two of the large Commercial rate classes, resulting in an overall reduction in demand for Whistler.

This section is organized as follows:

- RSAM
    - Discusses the method by which delivery margins for residential and commercial customers are stabilized
- Residential and Commercial Use Rates
    - Discusses forecast of average use rates for each rate schedule
- Customer Additions
    - Discusses forecast of net residential and commercial customer additions
- Demand Forecast
    - Discusses total energy demand for all residential and commercial rate schedules

- Revenue and Margin Forecast

4.6.2 REVENUE STABILIZATION ADJUSTMENT MECHANISM

Whistler utilizes an RSAM which stabilizes the margins recovered from all Residential and Commercial customers.

The RSAM stabilizes delivery margin received from Residential and Commercial customer classes on a UPC basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM deferral account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years.

Having an RSAM mechanism does not offer Whistler protection against forecasting errors due to variances between recorded and forecast number of customers.

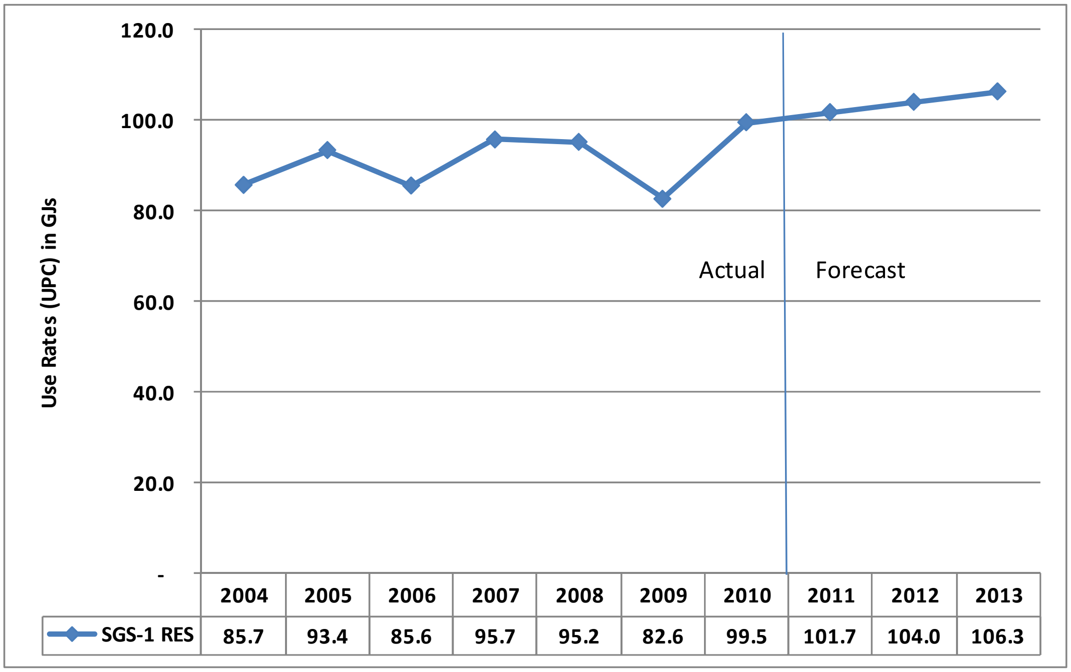
4.6.3 USE RATES

The average UPC forecast is the first component of determining the total energy demand. Individual average UPC projections are developed for each of the core market (Residential and Commercial) customer classes.

The forecast of average UPC has been developed by analyzing historical consumption. This is consistent with the approach taken in prior years, and forms an appropriate basis for the determination of total energy demand for this Application.

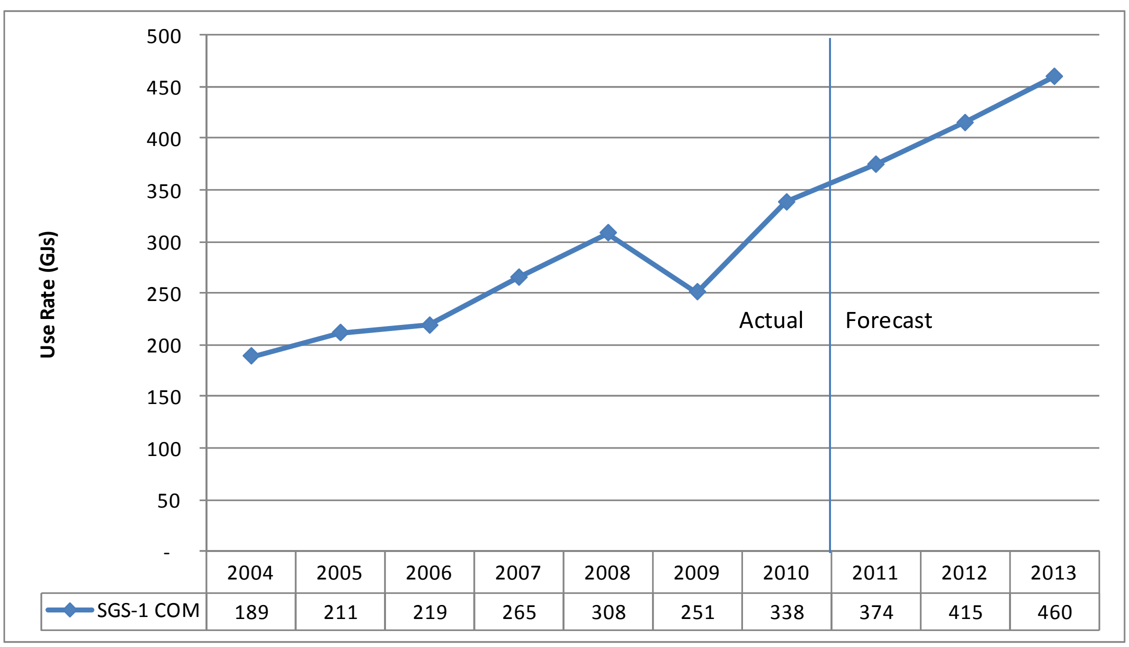
As shown below in Figure 4.6-1, Residential UPC is projected to increase approximately 2.3 percent annually during the forecast period.

Figure 4.6-1: Whistler - General Service Rate ("SGS-1") Residential UPC



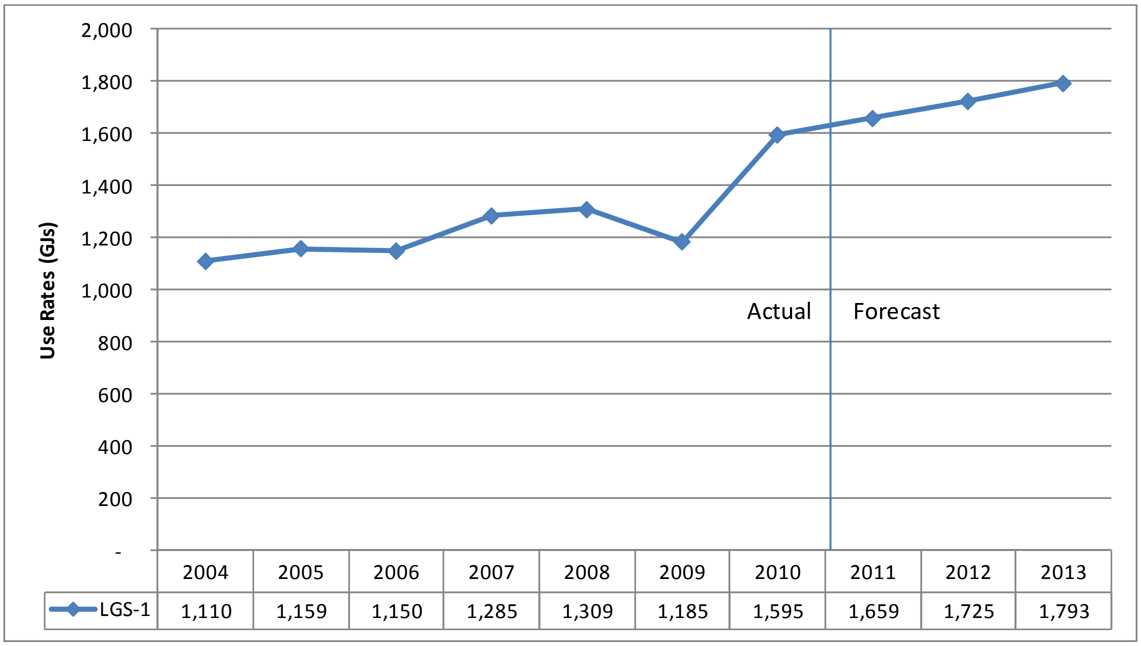
As shown in Figure 4.6-2 below, UPC for Rate Schedule SGS-1 is projected to increase by approximately 11 percent annually during the forecast period, consistent with our stated methodology and the trend observed in prior years.

Figure 4.6-2: Whistler - Rate SGS-1 Commercial UPC



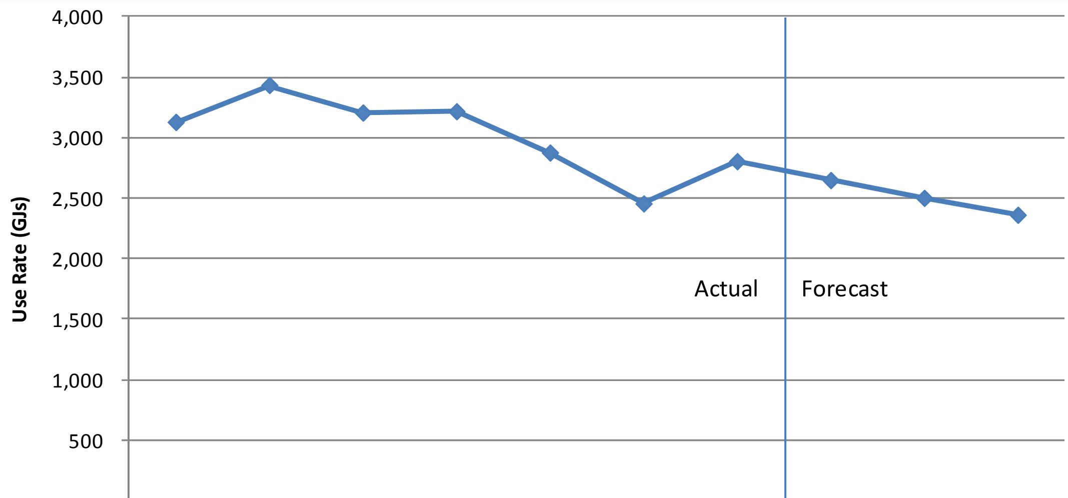
As shown in Figure 4.6-3 below, UPC for the Large General Service Rate No. 1 ("LGS-1") rate class is projected to increase by approximately 4 percent annually during the forecast period consistent with prior years.

Figure 4.6-3: Whistler - Rate Large General Service Rate No. 1 Commercial UPC



As shown in Figure 4.6-4 below, UPC for the Large General Service Rate No. 2 ("LGS-2") rate class is projected to decrease by approximately 6 percent annually during the forecast period consistent with prior years.

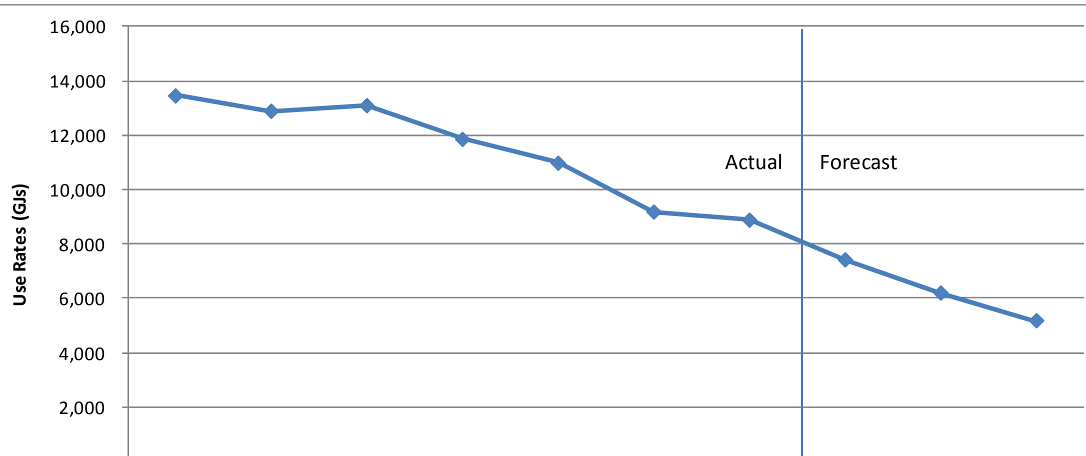
Figure 4.6-4: Whistler - Rate Large General Service Rate No. 2 Commercial UPC



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LGS-2	3,126	3,430	3,204	3,214	2,874	2,454	2,803	2,647	2,500	2,362

As shown in Figure 4.6-5 below, UPC for the Large General Service Rate No. 3 ("LGS-3") rate class is projected to decrease by approximately 17 percent annually during the forecast period consistent with prior years.

Figure 4.6-5: Whistler - Rate Large General Service Rate No. 3 Commercial UPC



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
LGS-3	13,456	12,889	13,093	11,853	10,972	9,175	8,872	7,409	6,187	5,167

The Resort Municipality of Whistler is actively working towards reducing its total emissions of greenhouse gases and although this is evidenced in the larger Commercial customer classes, the Residential and Small Commercial customer classes have moved into relatively stable ranges over the past few years.

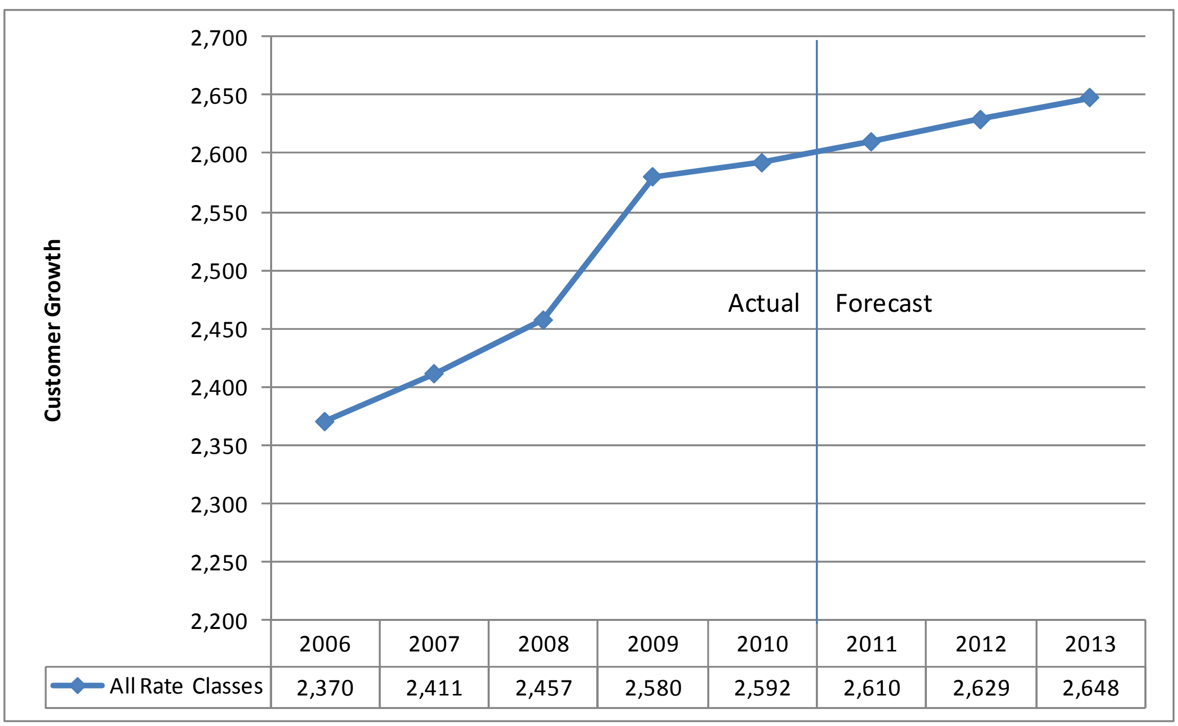
As described above, the forecast of average UPC has been developed by analyzing historical consumption and also considering other trends in the market. This is consistent with the approach taken in prior years, and forms an appropriate basis for the determination of total energy demand for this Application.

4.6.4 CUSTOMER ADDITIONS

The forecast of customer accounts is the second component of determining the total energy demand. There is a very strong correlation between the housing starts and the number of Whistler customer additions. The CMHC and the CBOC housing starts forecast provide a proxy for Whistler's customer additions. Market information, obtained through informal discussions with internal staff based in the region, is also incorporated when developing the forecast.

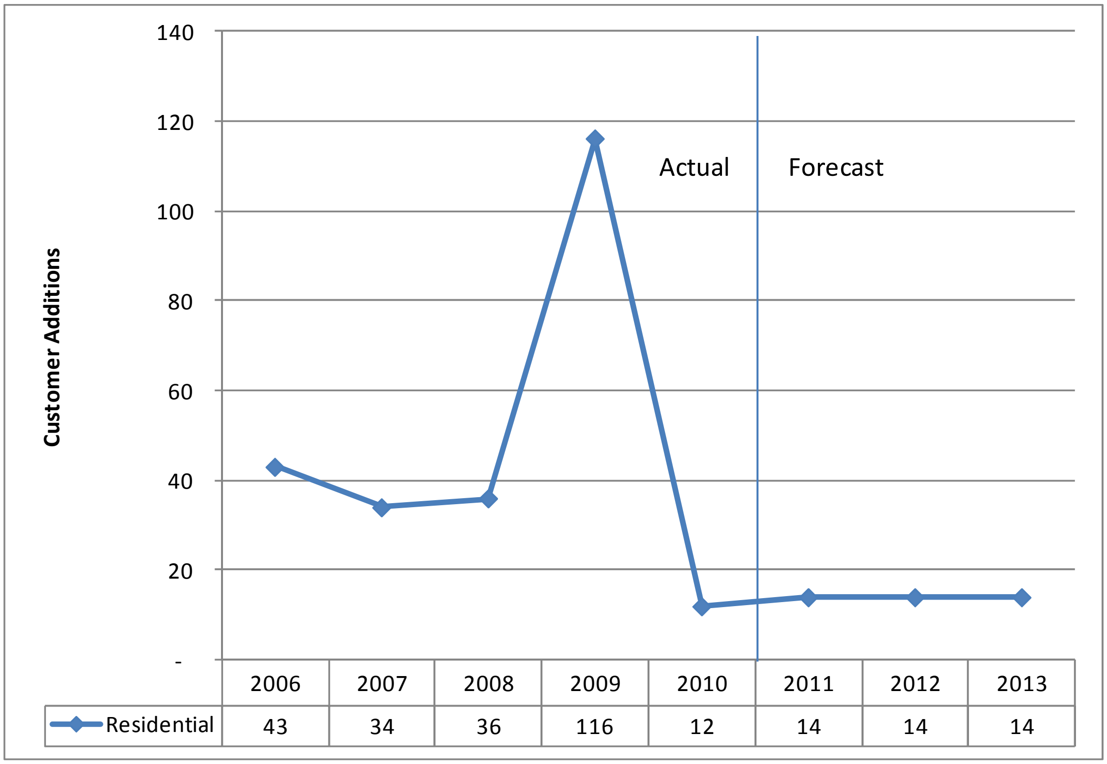
The total number of customers has continued to grow, with the majority of the growth being in the Residential segment as seen below in Figure 4.6-6. The level of growth experienced recently is forecast to continue, although at slightly lower levels.

Figure 4.6-6: Whistler - Total Customers



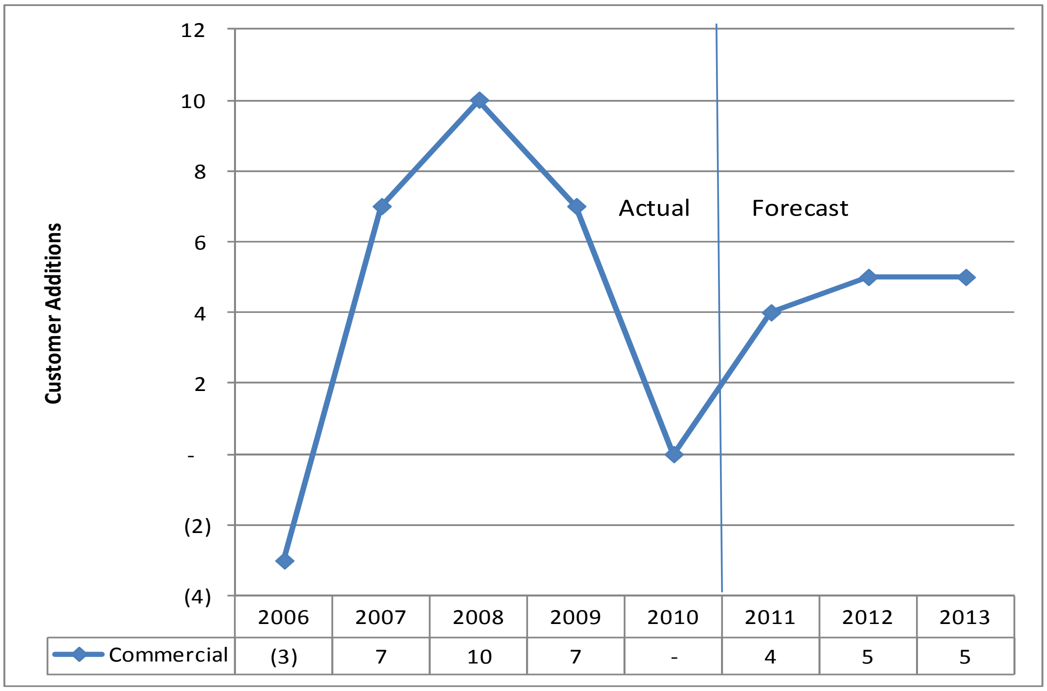
After a sharp increase prior to the 2010 Olympics Residential customers are expected to follow the CBOC trend and stabilize at 2010 level as illustrated in Figure 4.6-7 below.

Figure 4.6-7: Whistler - Residential Customer Additions



As shown in Figure 4.6-8 below, Commercial customer additions are continuing at a relatively modest pace, a result of the geographical constraints in the region and also the community's goal of managing growth in a sustainable manner.

Figure 4.6-8: Whistler - Commercial Customer Additions



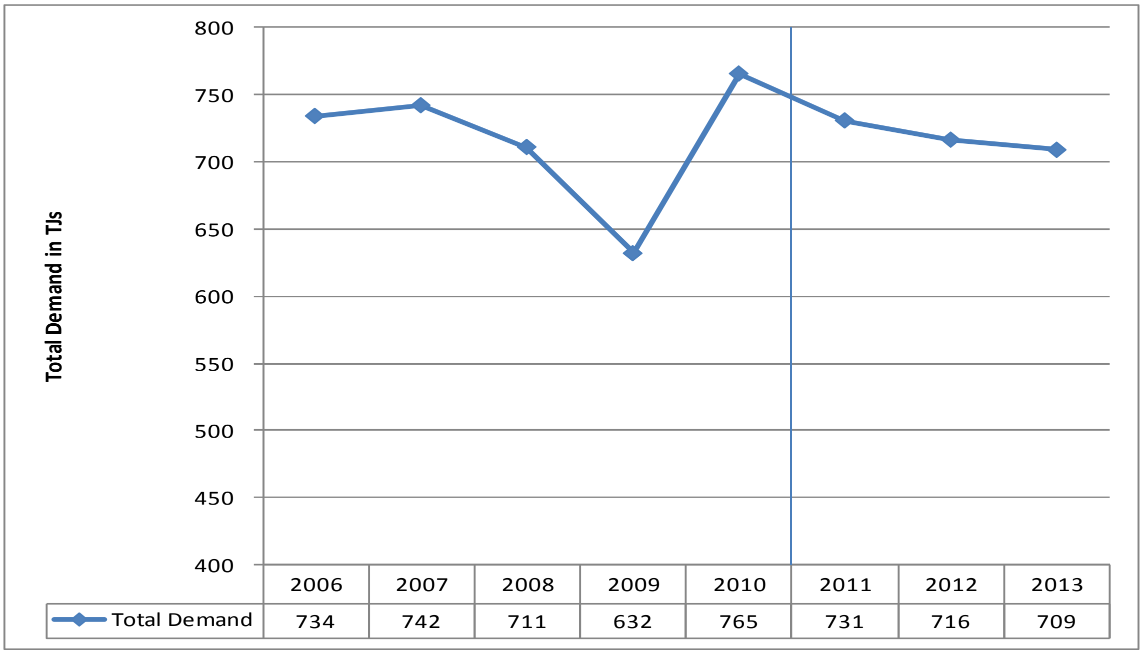
The above forecast of customer additions and total number of customers incorporates the best available information, and is based on a methodology that is consistent with prior years.

4.6.5 DEMAND FORECAST

As discussed previously, the energy demand forecast for each rate classes is derived by applying the total forecast customers, including customer additions, to the average UPC forecast for each rate classes. The total forecast energy demand for Whistler is the sum of the energy demand for the rate classes.

The following Figure 4.6-9 illustrates the historical and forecast normalized energy demand over the period 2006 to 2013. In spite of an increase in Residential demand the downward trend in Large Commercial UPC results in a decrease in total demand,

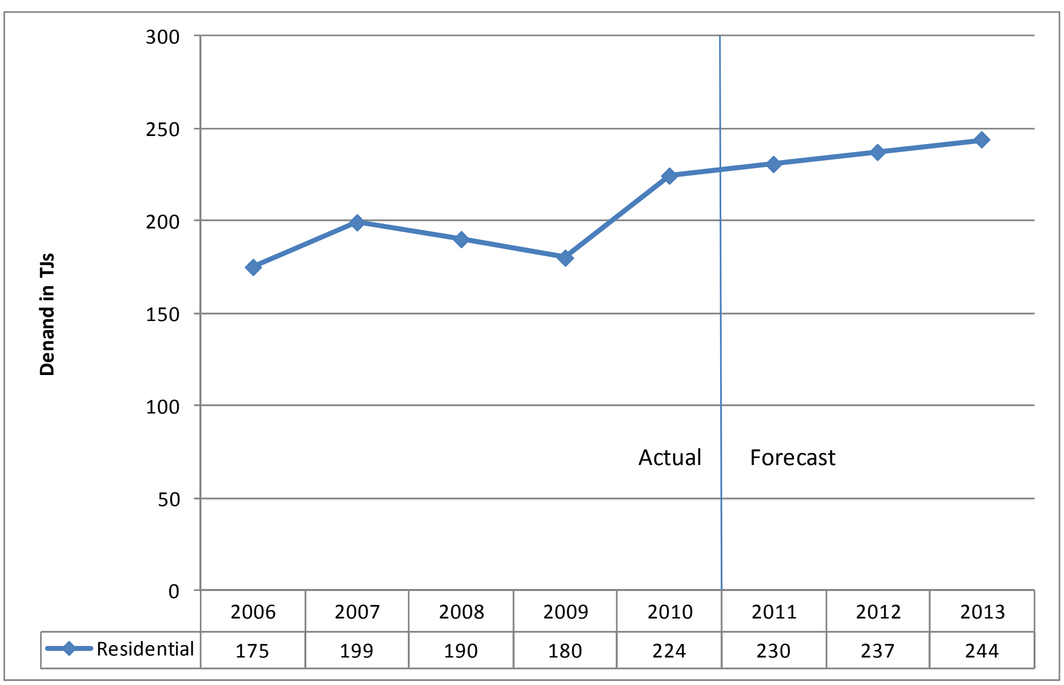
Figure 4.6-9: Whistler - Total Demand



	2006	2007	2008	2009	2010	2011	2012	2013
Total Demand	734	742	711	632	765	731	716	709

As seen in Figure 4.6-10 below, an increased UPC in SCS-1 Residential is expected to result in a slight increase in overall Residential demand.

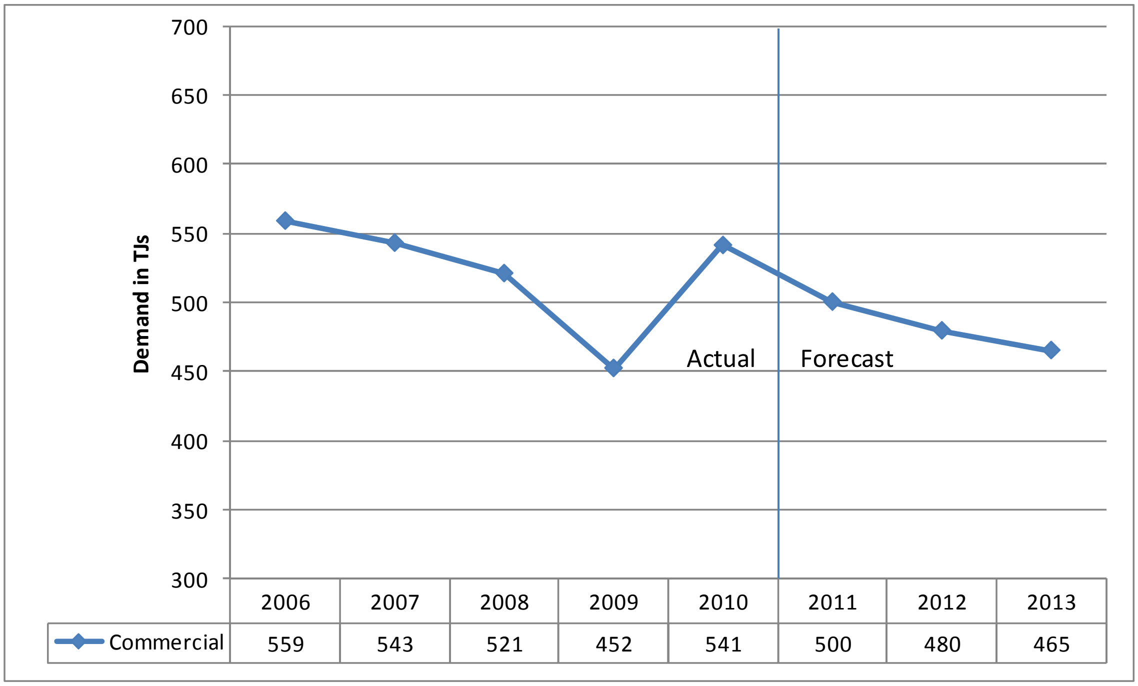
Figure 4.6-10: Whistler - Residential Demand



	2006	2007	2008	2009	2010	2011	2012	2013
Residential	175	199	190	180	224	230	237	244

As seen in Figure 4.6-11, total Commercial demand is projected to decline at approximately 5 percent per year for the forecast period.

Figure 4.6-11: Whistler - Commercial Demand



4.6.6 REVENUE AND MARGIN FORECAST

4.6.6.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. Whistler has developed its forecast of revenues by applying the total energy forecast to the currently approved rates for each customer segment.

Table 4.6-1 below summarizes the revenues projected for 2011 and forecast for 2012 and 2013, based on the currently approved rates in place at the time of the forecast.

Table 4.6-1: Forecast Sales Revenue for Whistler

Revenue ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Whistler			
Residential[1]	3.7	3.8	3.9
Commercial[2]	7.7	7.4	7.2
Grand Total	**11.4**	**11.2**	**11.1**

Notes:
1. SGS (Residential)
2. SGS (Commercial), LGS-1, LGS-2, LGS-3

4.6.6.2 Margin

Margins are a function of both total revenues and the cost of natural gas being provided to customers. The Company has developed a reasonable forecast of margins by first developing the forecast of revenues at existing approved rates and then subtracting from that the cost of natural gas.

Table 4.6-2 below summarizes the margin projected for 2011 and forecast for 2012 and 2013, by customer segment, at 2011 approved rates.

Table 4.6-2: Forecast Gross Margin for Whistler

Margin ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Whistler			
Residential[1]	2.6	2.7	2.8
Commercial[2]	5.3	5.0	4.9
Grand Total	**7.9**	**7.7**	**7.6**

Notes:
1. SGS (Residential)
2. SGS (Commercial), LGS-1, LGS-2, LGS-3

4.6.7 SUMMARY

Through considering the factors influencing customer additions, average UPC, and Transportation volumes, Whistler has developed a forecast of demand for natural gas. As a result, total forecast energy demand will remain relatively stable over the forecast period rather than experience the increase Whistler saw in 2010. It is through considering those factors influencing natural gas consumption, applying a methodology consistent with prior years, and by using the latest and best information available that Whistler believes it has developed a reasonable demand forecast that is the most appropriate to be used in this RRA.

4.7 Fort Nelson Demand Forecast and Revenues

4.7.1 INTRODUCTION

This section describes the forecast of average UPC, customer additions and total energy demand over the forecast period for the Fort Nelson region.

In order to forecast the Fort Nelson total energy demand Fort Nelson considers the following:

- Average Use rates by rate class;
- Customer Additions; and
- Industrial Demand.

These three inputs together form the basis for the forecast. A modest increase in Rate Schedule 2.2 UPC is forecast to offset the slight decline in Rate Schedule 1B Residential UPC, resulting in a small increase in overall demand. Industrial demand is forecast to remain flat.

This section is organized as follows:

- RSAM
    - Discusses the method by which delivery margins for residential and commercial customers are stabilized
- Residential and Commercial Use Rates
    - Discusses forecast of average use rates for each rate schedule
- Customer Additions
    - Discusses forecast of net residential and commercial customer additions
- Demand Forecast
    - Discusses total energy demand for all residential, commercial and industrial rate schedules
- Revenue and Margin Forecast

4.7.2 REVENUE STABILIZATION ADJUSTMENT MECHANISM

Fort Nelson utilizes an RSAM which stabilizes the margins recovered from Fort Nelson Residential and Commercial customers.[69]

The RSAM stabilizes delivery margin received from Residential and Commercial customer classes on a UPC basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, the Company records the delivery charge differences in the RSAM deferral account for refunding or charging through a rate rider to the RSAM rate classes over the ensuing three years.

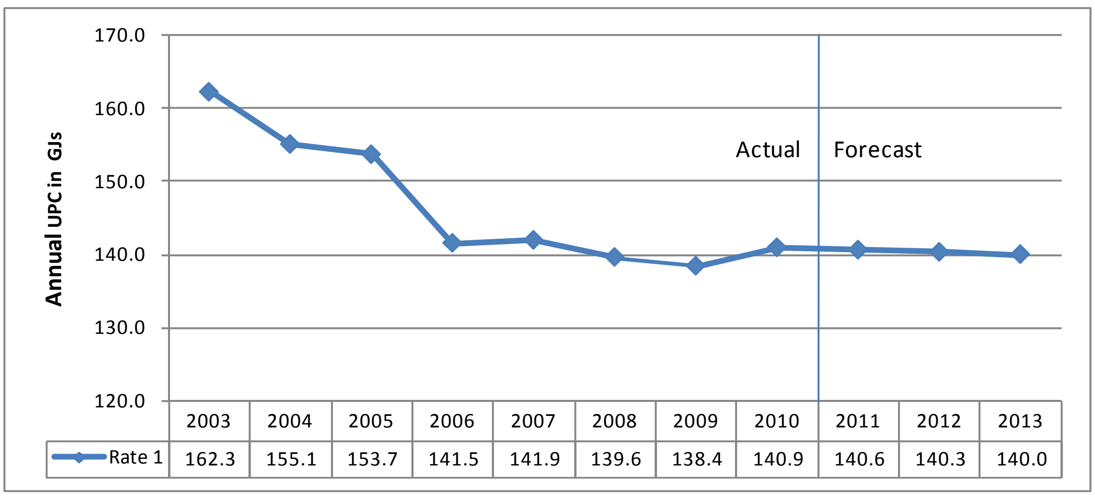
Having an RSAM mechanism does not offer Fort Nelson protection against forecasting errors due to variances between recorded and forecast number of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as Industrial customers.

4.7.3 USE RATES

Individual UPC projections are developed for each rate class by considering the recent historical weather-normalized use per account.

The Rate Schedule 1 UPC is stable through the forecast period as seen in Figure 4.7-1 below.

Figure 4.7-1: Fort Nelson - Residential UPC for Rate Schedule 1B

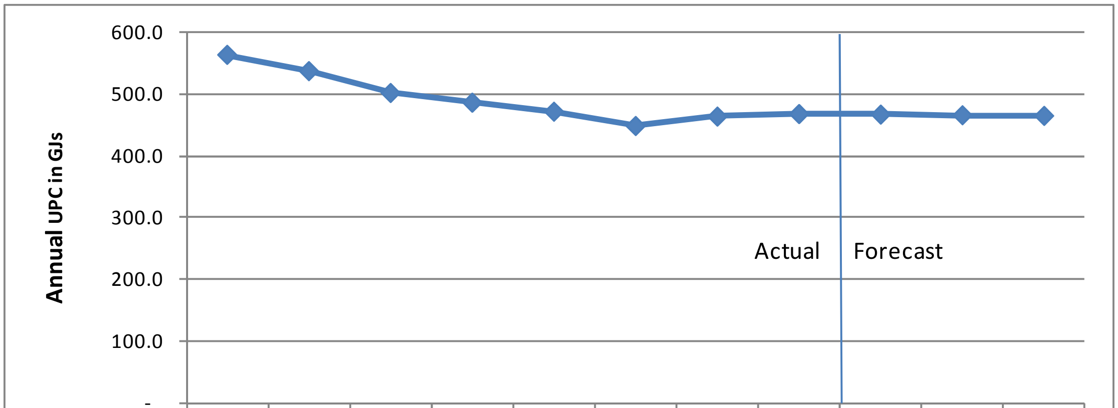


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 1	162.3	155.1	153.7	141.5	141.9	139.6	138.4	140.9	140.6	140.3	140.0

Rate Schedule 2.1 has stabilized in recent years as seen in Figure 4.7-2 below. This trend is expected to continue throughout the forecast period.

[69] Fort Nelson Rate Schedules 1, 2.1, 2.2 and 25

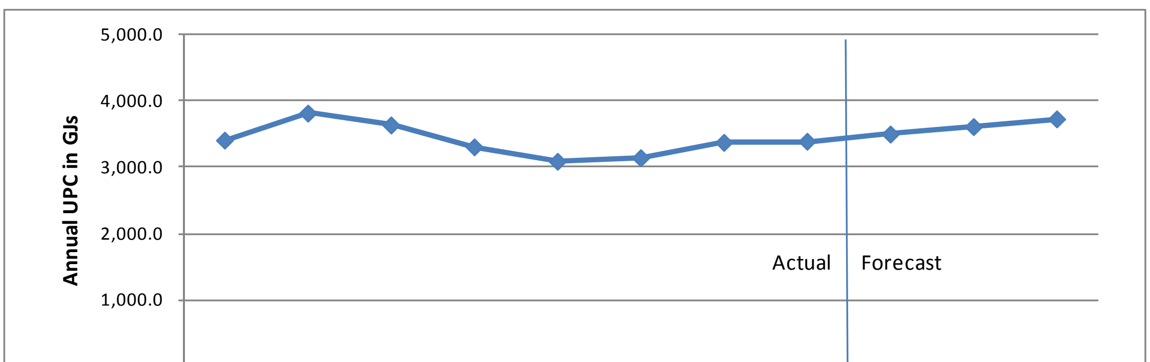
Figure 4.7-2: Fort Nelson - Commercial UPC for Rate Schedule 2.1



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 2.1	563.6	537.3	502.1	486.5	472.0	448.9	464.0	468.1	467.2	466.2	465.2

Rate Schedule 2.2 is showing an increase in recent years as seen in Figure 4.7-3 below. The forecast for 2011 continues the trend which will result in moderate growth through the forecast period.

Figure 4.7-3: Fort Nelson - Commercial UPC for Rate Schedule 2.2



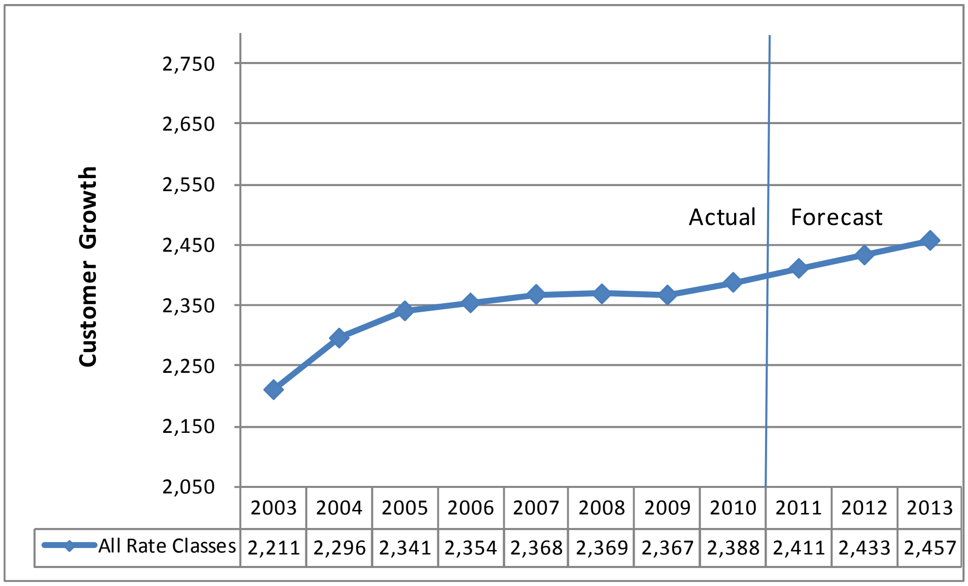
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 2.2	3,404.2	3,814.7	3,634.5	3,302.8	3,083.7	3,137.1	3,370.7	3,387.5	3,496.7	3,609.4	3,725.7

4.7.4 CUSTOMER ADDITIONS

The forecast of customer accounts is the second component of determining the total energy demand. The CBOC housing starts forecast provide a proxy for Fort Nelson's customer additions. Market information, obtained through discussions with internal staff based in the region, is also incorporated when developing the forecast.

The total number of customers has continued to grow in both residential and commercial segments. The level of growth experienced recently is forecast to continue.

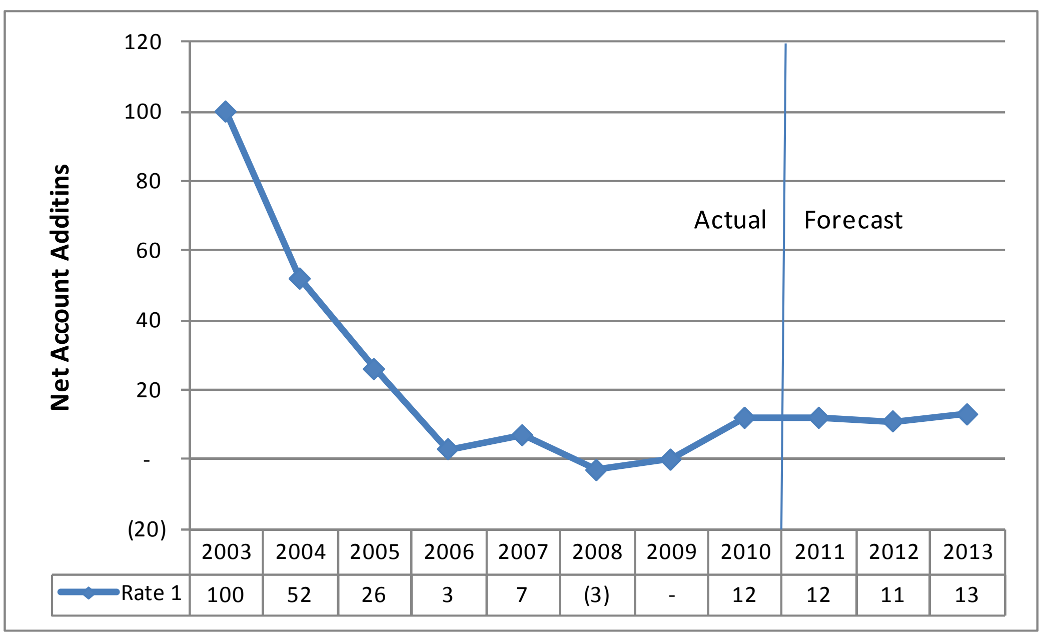
Figure 4.7-4: Fort Nelson - Total Customers



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
All Rate Classes	2,211	2,296	2,341	2,354	2,368	2,369	2,367	2,388	2,411	2,433	2,457

As shown in Figure 4.7-5 below the customer additions in the Fort Nelson region have been minimal since 2006. In 2010 there were 12 net additions and additions at this level are predicted for the forecast period.

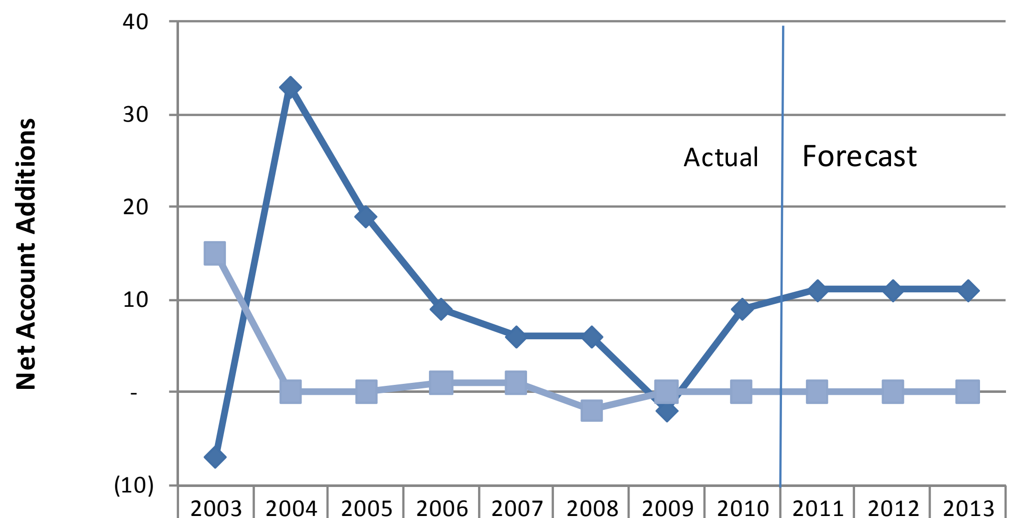
Figure 4.7-5: Fort Nelson - Residential Customer Additions



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 1	100	52	26	3	7	(3)	-	12	12	11	13

New construction for Small Commercial customers has been low and uncertain in Fort Nelson in recent years. There is the completion of construction of a new recreation centre in 2011, which will bring additional consumption near the latter part of 2011 and going forward into 2012. However, there are no other Small Commercial projects planned for construction in 2012 or 2013. Commercial customer additions are seen in Figure 4.7-6 below.

Figure 4.7-6: Fort Nelson - Commercial Customer Additions

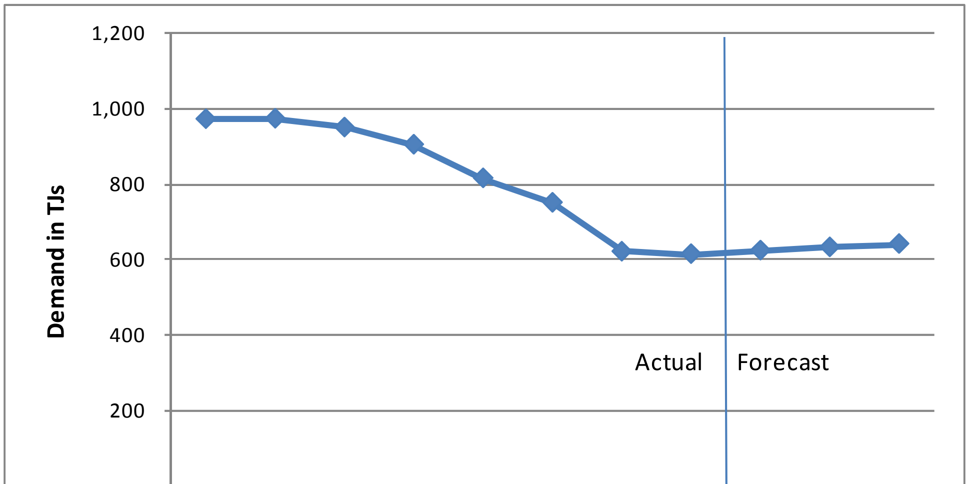


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 2.1	(7)	33	19	9	6	6	(2)	9	11	11	11
Rate 2.2	15	-	-	1	1	(2)	-	-	-	-	-

4.7.5 DEMAND FORECAST

As discussed previously, the energy demand forecast for each rate class is derived by applying the total forecast customers, including customer additions, to the average UPC forecast for each rate class. The total forecast energy demand for Fort Nelson is the sum of the energy for the individual rate classes. The following Figure 4.7-7 illustrates the historical and forecast normalized energy demand over the period 2003 to 2013. Fort Nelson is forecasting a slight increase in total energy demand for 2012 and 2013.

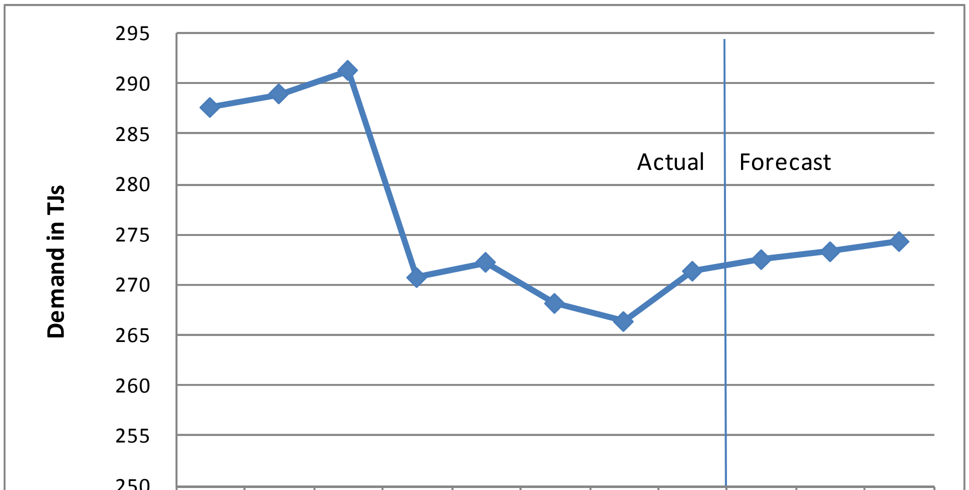
Figure 4.7-7: Fort Nelson - Total Energy Demand



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total	973	974	951	905	816	751	621	615	624	633	642

As seen in the Figure 4.7-8 below, the modest increase in Rate Schedule 1B customers is expected to result in a slight increase in overall Residential demand.

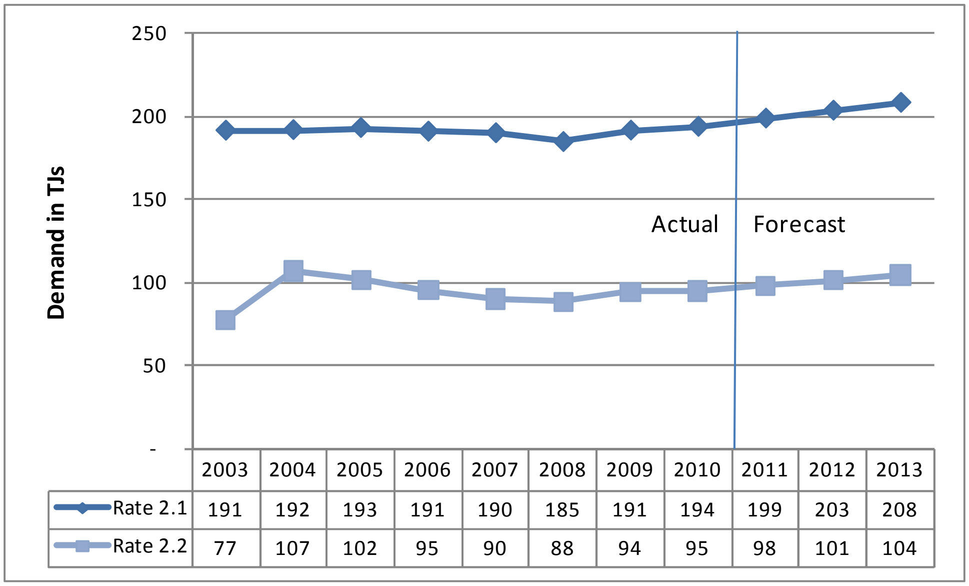
Figure 4.7-8: Fort Nelson - Residential Energy Demand



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 1	288	289	291	271	272	268	266	271	273	273	274

As seen in Figure 4.7-9 below, the modest increase in Rate Schedule 2.1 is the result of the increase in customers. On the other hand, the increase demand seen in Rate Schedule 2.2 is the result of a slight increase in the UPC for this rate class.

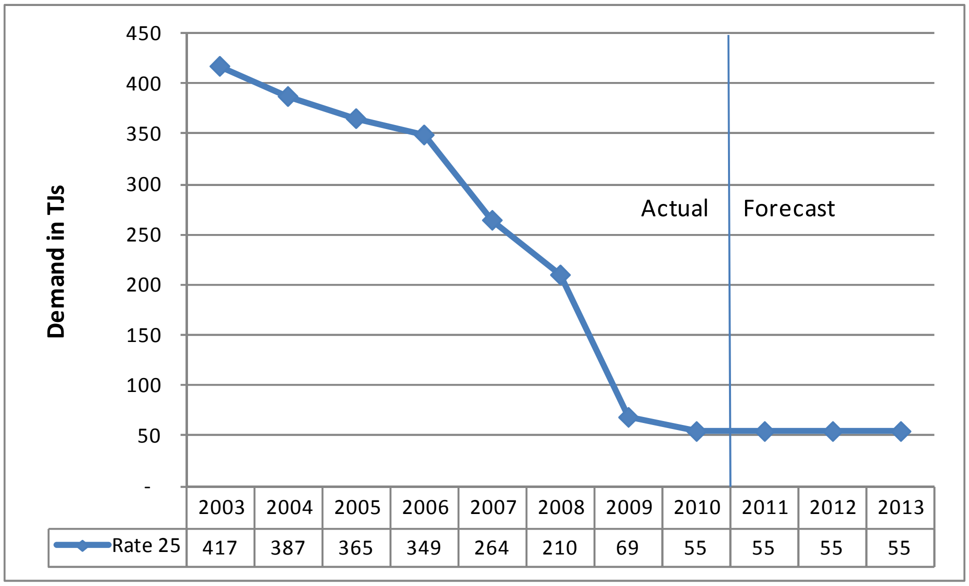
Figure 4.7-9: Fort Nelson - Commercial Energy Demand



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate 2.1	191	192	193	191	190	185	191	194	199	203	208
Rate 2.2	77	107	102	95	90	88	94	95	98	101	104

Canfor remains the only Industrial customer served under Rate Schedule 25 in the Fort Nelson region. The continuing downturn in the U.S. housing markets has caused difficulties within the forestry industry. The closure in 2008 of Canfor's two facilities in Fort Nelson resulted in these two plants maintaining only heat load consumption. Although there aren't any operating mills in Fort Nelson their heating load consumption can fluctuate from year to year. The Industrial Energy Demand is seen in Figure 4.7-10 below.

Figure 4.7-10: Fort Nelson - Industrial Energy Demand



4.7.6 FORT NELSON REVENUE AND MARGIN FORECAST

4.7.6.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. Fort Nelson has developed its forecast of revenues by applying the total energy forecast to the currently approved rates for each customer segment.

Table 4.7-1 below summarizes the revenues projected for 2011 and forecast for 2012 and 2013, based on the currently approved rates in place at the time of the forecast.

Table 4.7-1: Forecast Sales Revenue for Fort Nelson

Revenue ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Fort Nelson			
Residential[1]	2.1	2.1	2.2
Commercial[2]	2.4	2.5	2.5
Industrial[3]	0.1	0.1	0.1
Grand Total	**4.7**	**4.8**	**4.8**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2
3. Rate Schedule 25

4.7.6.2 Margin

Margins are a function of both total revenues and the cost of natural gas being provided to customers. The Company has developed a reasonable forecast of margins by first developing the forecast of revenues at existing approved rates and then subtracting from that the cost of natural gas.

Table 4.7-2 below summarizes the margin projected for 2011 and forecast for 2012 and 2013, by customer segment, at 2011 approved rates

Table 4.7-2: Forecast Gross Margin for Fort Nelson

Margin ($ millions)	Projected 2011	Forecast 2012	Forecast 2013
Fort Nelson			
Residential[1]	0.8	0.8	0.8
Commercial[2]	0.9	1.0	1.0
Industrial[3]	0.1	0.1	0.1
Grand Total	**1.8**	**1.9**	**1.9**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2
3. Rate Schedule 25

4.7.7 SUMMARY

Fort Nelson developed the forecast demand for natural gas with reference to the factors influencing customer additions and average UPC. It is through considering factors influencing natural gas consumption, applying a methodology consistent with prior years, and by using the latest and best information available that Fort Nelson believes it has developed a reasonable demand forecast that is the most appropriate to be used in this RRA

4.8 Conclusion to Demand Forecast and Revenues

Through considering the factors influencing customer additions, average use per customer, and also industrial volumes the Company has developed a demand for natural gas.

- In the Mainland region the overall growth in Residential customers has not offset the decline in average Residential UPC, which has resulted in a decline in overall Residential energy demand. However, increased UPC in selected Commercial and Industrial rate classes is expected to offset this decline in Residential demand resulting in the overall slight increase in total demand for 2012 and 2013.

- On Vancouver Island in 2011 an increase in the confirmed contract demand compared to 2010 actuals will not be offset by the reduction in residential and commercial demand. For the remainder of the forecast period the total energy demand for all customer classes is expected to remain relatively stable.

- A modest increase in customers coupled with a 2 GJ increase in Residential UPC is forecast to result in an increased Residential demand for Whistler. This increase is expected to be offset by a decrease in two of the large Commercial rate classes, resulting in an overall reduction in demand for Whistler.

- A modest increase in Rate Schedule 2.2 UPC is forecast to offset the slight decline in Rate Schedule 1B Residential UPC, resulting in a small increase in overall demand. Industrial demand is forecast to remain flat in the Fort Nelson region.

The forecast of demand for natural gas included in the RRA is based upon a methodology that is consistent with that used in prior years and fairly represents the expected customer additions and average UPC for 2012 and 2013. This forecast of demand for natural gas is appropriate to be used in the determination of rates for the 2012 and 2013 forecast period.

5 COST OF SERVICE

5.1 Introduction to Cost of Service

FEU's revenue requirements are composed of the changes in revenue at existing rates (Section 4) and the cost of service.

Of these two components, changes in the cost of service have the biggest impact on the revenue requirement. Section 5 describes all of the components of the cost of service, and the changes in the forecast components for 2012 and 2013.

The cost of service is composed of:

1. Cost of gas (Section 5.2)
2. Operations and maintenance expenses (Section 5.3)
3. Depreciation and amortization expense (Section 5.4)
4. Other revenue (Section 5.5)
5. Taxes (Section 5.6)
6. Financing Costs and ROE (Section 5.7)

In turn, the depreciation and amortization and financing costs and ROE sections are dependent on the rate base forecasts included in Section 6.

Each of the following sections describes how the components have been calculated. The forecasts included in the following sections appropriately reflect the reasonable costs required for FEU to continue to meet the needs of our customers and the communities in which we serve.

5.2 Cost of Gas

5.2.1 INTRODUCTION TO COST OF GAS

This section of the Application describes the cost of gas, where the term "gas" refers to natural gas, propane, and biomethane, for the FEU. Biomethane makes up a very small component of the FEU gas supply portfolio and the biomethane costs are discussed in Appendix J. The total cost of gas is forecast to be approximately $740.1 million in 2012 and $741.4 million in 2013. Effectively managing these costs is essential to providing reliable and cost effective service to customers.

Table 5.2-1: Cost of Gas Forecasts[70]

($ thousands)

Utility/Region	Forecast 2012	Forecast 2013
Mainland	$659,338	$658,568
Vancouver Island	74,337	76,399
Whistler	3,493	3,455
Fort Nelson	2,900	2,945
Total	**$740,068**	**$741,367**

5.2.2 MANAGING GAS COSTS TO ENSURE RELIABLE, COST EFFECTIVE SUPPLY

The total cost of gas is comprised of the forecast natural gas and propane commodity costs, and the forecast costs for midstream components (storage and transportation). The gas costs for Mainland, Whistler, Fort Nelson, and Revelstoke sales rate customers are reviewed and approved in separate applications by the Commission and FEI (including Fort Nelson and Revelstoke) and FEW are not requesting approval of those forecast gas costs as part of this Application. These forecast gas costs are, however, required to determine a number of revenue requirement line items that form part of this Application.

Unlike FEI and FEW, FEVI is requesting approval of its forecast cost of gas, as described in Section 5.2.3.2, in order to determine the approved cost of gas, as variances between the approved and incurred cost of gas are recorded in the Gas Cost Variance Account, which is further described in Section 6.3. The FEVI forecast gas costs are also required to determine a number of revenue requirement line items that form part of this Application.

5.2.2.1 Gas Supply Management

Gas Supply is the area within the Energy Supply and Resource Planning department that manages the Companies' natural gas and propane supply functions. The department ensures that there are reliable, secure and cost effective supplies of natural gas and propane for Mainland, Vancouver Island, Whistler, Fort Nelson, and Revelstoke customers. The gas supply function encompasses most elements of the merchant role, providing supply to firm and interruptible customers. The cost to complete these management activities is included in Core Market Administration Expense ("CMAE") and forms part of the cost of gas. CMAE is discussed in more detail later in this section.

The key objectives relating to the management of natural gas and propane supply include:

- providing natural gas and propane supply to customers;

[70] Section 7.1 to 7.4, Schedule 13

- optimizing resources to minimize the overall supply portfolio costs for the benefit of customers;
- managing market price risk to reduce volatility on resulting rates for customers; and
- providing Energy Management Services to create value for customers through revenue generation.

The development and implementation of the Annual Contracting Plans and Price Risk Management Plans play a critical role in managing these objectives. Although separate applications are filed with the Commission for approval of these plans, it is helpful to understand their role in how gas costs are managed.

The Annual Contracting Plans outline the portfolio requirements to meet the needs of core customers[71] under design day conditions through contracting for an optimal and diversified mix of commodity, storage, and transportation resources. The plans outline procurement requirements in detail and address longer term gas supply and infrastructure issues, particularly those within the BC marketplace and the Pacific Northwest region.

The Price Risk Management Plans satisfy the primary objectives of reducing market price volatility and resultant rate volatility for customers. Price Risk Management Plans further serve to improve the likelihood of gas remaining competitive with other sources of energy in order to retain and attract customers.

Other key department functions include: providing intra-day balancing supply (required primarily due to weather changes) for core customers; facilitating all gas scheduling and nominations on the Companies owned and third party pipeline transmission systems; performing mitigation activity based on buying and selling around excess resources; and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies.

The Gas Supply department also provides Energy Management Services for other natural gas and propane utilities, currently this is done for Pacific Northern Gas Ltd. (“PNG”) and Northwest Natural Gas Company (“NWN”).

5.2.3 COST OF GAS BY SERVICE AREA

With the exception of the Vancouver Island service area, the gas cost recovery rates are subject to quarterly review and resetting, as necessary. The sections below provide details for the FEU service areas.

[71] Core customers are those for whom FEU is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.

5.2.3.1 Mainland and Whistler Cost of Gas

For the 2012 and 2013 forecast period, the total cost of gas sold is comprised of the commodity and the midstream components and it is determined by multiplying forecast sales volumes by the approved forecast unit gas cost recovery charges for each rate schedule. The commodity cost recovery charge for the natural gas sales rate customers is subject to quarterly review by the Commission, and FEI and FEW are not requesting approval of forecast gas costs with this Application; however, forecast gas costs are required in the determination of a number of revenue requirement line items.

The currently approved gas cost recovery charges were set with the 2011 First Quarter Gas Cost reports that were filed on March 3, 2011. The gas cost recovery rates for the Mainland and Whistler customers effective April 1, 2011 remained unchanged from the January 1, 2011 rates, as accepted by Commission Letters No. L-13-11 and No. L-12-11,respectively.

5.2.3.2 Vancouver Island Cost of Gas

The forecast gas costs included in the Application for the 2012 and 2013 test year periods are based on the NYMEX natural gas futures five-day average forward prices at February 15, 16, 17, 18, and 22, 2011 (the "February 22, 2011 Five-Day Average Forward Prices"). The February 22, 2011 Five-Day Average Forward Prices align with the commodity forward prices used in the FEVI 2011 First Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account, submitted to the Commission on March 4, 2011.

Vancouver Island's cost of gas reflects the costs related to commodity, transportation, and storage resources and the impacts of the hedging program. The cost of gas also includes unaccounted for gas, company use gas, carbon tax and CMAE costs as discussed within this section.

The Royalty Rebate arrangement under which Vancouver Island has received royalty revenues from the Province expires on December 31, 2011, therefore the 2012 and 2013 forecast cost of gas does not include any forecast royalty revenues. The projected cost of gas for 2011, excluding royalty revenues, and the forecast cost of gas for 2012 and 2013 are shown in Table 5.2-2 below.

Table 5.2-2: Vancouver Island 2011-2013 Cost of Gas Excluding Royalty Revenues and GCVA Impacts

	Amounts in $ Thousands		
	2011 Projected	**2012 Forecast**	**2013 Forecast**
Commodity	$ 38,841	$ 46,828	$ 51,919
Transportation Demand Charges	7,451	8,173	7,584
Storage Demand Charges	3,457	3,499	3,432
Hedging Cost / (Gain)	16,394	15,174	12,786
Gas Supply Management Costs	630	663	678
Total Cost of Gas	$ 66,773	$ 74,337	$ 76,399

With this Application, FEVI seeks approval of the 2012 and 2013 cost of gas. Variances between the actual incurred cost of gas and the approved forecast cost of gas for the two-year period of the 2012-2013 revenue requirements will be captured in the GCVA for amortization through future rates.

5.2.3.3 Fort Nelson Cost of Gas

For the 2012 and 2013 forecast period, the forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The gas cost recovery charges for the sales rate customers are subject to quarterly review by the Commission, and Fort Nelson is not requesting approval of forecast gas costs with this Application. Forecast gas costs are, however, required in the determination of a number of revenue requirement line items.

The currently approved gas cost recovery charge was set with the 2011 First Quarter Gas Cost report that was filed on March 3, 2011. The gas cost recovery rates for Fort Nelson customers effective at April 1, 2011 remained unchanged from January 1, 2011 rates, as accepted by Commission Letter No. L-16-11.

5.2.3.4 Revelstoke Cost of Gas

For the 2012 and 2013 forecast period, the forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The approved propane reference price, and corresponding gas cost recovery charges, for the sales rate customers are subject to quarterly review by the Commission, and Revelstoke is not requesting approval of forecast gas costs with this Application. Forecast gas costs are, however, required in the determination of a number of revenue requirement line items.

The currently approved gas cost recovery charge was set with the 2011 First Quarter Gas Cost report that was filed on March 3, 2011. The gas cost recovery rates for Revelstoke customers effective April 1, 2011 remained unchanged from January 1, 2011 rates, as accepted by Commission Letter No. L-15-11.

5.2.4 OTHER COMPONENTS OF THE COST OF GAS

Aside from the cost of the natural gas commodity and midstream resources, a number of other components are managed by FEU and form part of the cost of gas.

5.2.4.1 Unaccounted for Gas ("UAF")

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Consistent with past practice, the UAF percentages are calculated based on the average historical recorded UAF percentages. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered from core customers via the gas cost rates; whereas the cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates.

5.2.4.2 Company Use Gas ("Own Use Fuel")

FEU company gas use, or own use fuel, is required to deliver natural gas to customers in a safe and efficient manner and represents a significant cost for the Operations and Facilities business areas. Company use gas is consumed as distribution line heater fuel, transmission compressor fuel and LNG plant fuel, as well as gas used in the Companies' facilities and offices. In its letter to the Commission dated April 15, 2011, FEI has requested approval for the use of a hedge based on the Sumas price and the forecast volumes, and for continuation of the practice of accounting for volume variances within the MCRA, for Mainland company use gas for 2012 and 2013. This request is consistent with the treatment of own use gas in 2010 and 2011. At the time of preparing this Application, the Company has not yet received approval for the recommended hedging and treatment of volume variances sought. However, when approval is received, a hedge will be entered into based on the forecast volumes for 2012 and 2013.

The Vancouver Island system requires company use gas to fuel line heaters and compressors in order to move gas supply to customers. A higher proportion of company use gas is required for Vancouver Island compressors for its daily operations, as compared to the Mainland system, primarily due to its relatively higher pressure transmission system. Company use gas consumed by Vancouver Island is included in the cost of gas, consistent with past practice, except for company use gas that is used in facilities. This facilities cost is included in O&M.

5.2.4.3 Gas Control Services

The Vancouver Island cost of gas includes a charge related to services provided by the Gas Control group in the Energy Supply & Resource Development department for monitoring and operating the Vancouver Island transmission system. The costs are related to labour expenses and the SCADA system used to monitor the flows and conditions on the Vancouver Island transmission system. The forecast amounts for 2012 and 2013 are approximately $220 thousand per year, increased by an inflation factor over time. These costs are included in the cost of gas for Vancouver Island. For the Mainland, the cost of Gas Control is included in O&M. Differences in the treatment of some of the gas supply related costs between the various FEU entities are a result of the historical separate rate design processes for each entity, and is one of the items that will be included in the upcoming Rate Design Application.

5.2.4.4 Core Market Administration Expense

CMAE costs are a direct result of the management activities performed within the Gas Supply area to serve core market customers and are treated as a flow-through cost to core market customers as part of gas costs. Providing safe, reliable, and cost effective gas supply resources that are required to meet core customers' load demands is the central purpose of CMAE activities. These CMAE activities have been provided on the basis of a single administrative function since 2004 and are allocated between the gas supply portfolios for the Mainland, including Whistler, and Vancouver Island based on customer count. Further, the CMAE costs for the Mainland, including Whistler, are allocated between the CCRA and MCRA accounts based on the activities performed by employees in the Gas Supply area, with 30 percent allocated to the CCRA and 70 percent allocated to the MCRA.

CMAE BUDGET REQUIREMENTS

For the purposes of this Application, CMAE costs are presented on a consolidated basis. The CMAE forecast costs will continue to be allocated to the Mainland and Vancouver Island based on using customer count as the allocation methodology. For 2012 and 2013 this equates to 90 percent for the Mainland (including Whistler) and 10 percent to Vancouver Island, which is the same allocation used for 2010 and 2011. Historical and forecast consolidated CMAE annual expenditures are shown below (with the projection for 2011).

Table 5.2-3: CMAE Forecast

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 3,610	$ 3,309	$ 3,732	$ 3,732	$ 3,982	$ 4,112
Vancouver Island	$ 401	$ 368	$ 415	$ 415	$ 442	$ 457
Total	$ 4,011	$ 3,677	$ 4,147	$ 4,147	$ 4,424	$ 4,569

Expenditures in 2010 were $334 thousand lower than approved. The decrease in actual expenditures was caused by several vacant positions that were not filled until later in the year and because legal fees were lower than expected for work assisting with the intervention and review of third party pipeline transportation toll and tariff applications. The reductions in CMAE expenditures in 2010 are considered one-time savings only and flowed to customers as a direct savings as part of the cost of gas. Expenditures in 2011 reflect the amount approved in the RRA for 2010 and 2011 and are not projected to vary materially.

For 2012, expenditures are forecast to increase by $277 thousand and in 2013 by an additional $145 thousand. The increase in expenditures forecast for 2012 is caused by the need for an additional employee required to assist in the completion of Gas Supply activities, by labour and materials inflation, and the need to support several enhancements to the information systems used by Gas Supply. The increase in expenditures forecast for 2013 is caused by labour and materials inflation.

The following table shows the historical, projected, and forecast for 2012 and 2013 headcount (expressed as full time equivalents) required by Gas Supply to complete CMAE responsibilities.

Table 5.2-4: CMAE Historical and Forecast Employees

Total FTEs						
	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
CMAE	21	20	21	22	22	22

The total number of employees required to meet CMAE's responsibilities is not expected to change in 2012 or 2013 from the number projected for 2011. One employee is expected to be added in 2011 and is required to assist in the completion of Gas Supply activities.

5.2.5 CONCLUSION

The cost of gas includes the forecast natural gas and propane costs, the midstream related costs, and the costs associated with providing natural gas and propane supply services. Natural gas and propane resources are contracted by the Gas Supply department to meet the objectives of safe, reliable and cost effective supply for core customers.

Having effective natural gas and propane supply management is necessary to help ensure reliable, secure, and cost effective supplies of natural gas and propane to customers. The costs related to the Gas Supply function are reflected in the CMAE budget and included in the cost of gas flowed through to customers via rates. The Companies believe the costs presented in this Application are prudent and necessary to ensure safe and reliable gas service for customers.

5.3 Operations and Maintenance Expense

5.3.1 INTRODUCTION TO OPERATIONS AND MAINTENANCE EXPENSE

The FortisBC Energy Utilities' O&M expenditures are required to operate the system and provide administrative support to the business. The 2012 and 2013 O&M expense forecasts have been developed in support of the Companies' business priorities and objectives, ensuring that O&M funding is appropriate and prioritized to meet the current and longer-term needs of customers. Key priorities and focus for the utilities in the near future include customer service repatriation, public and employee safety, customer satisfaction, financial management, environmental responsibility and system sustainment, and the demographic challenges we face with our aging workforce.

To plan for allocation of financial resources, FEU reviews, updates and approves its O&M budgets annually, as described in Section 3.1.4. Forecast O&M expenditures by departments are developed on a trended and zero-based approach where appropriate. Departments review their existing O&M budgets and identify savings and/or incremental funding requests with supporting justification provided. Budgeting using this comprehensive approach helps to ensure an appropriate allocation of resources amongst the various departments.

For historical information for each of the Companies please refer to Appendix D.

O&M costs are budgeted for each of FEU's departments. These departments are:

- Operations (Distribution & Transmission) - manages the distribution and transmission assets and operates the gas system safely, reliably and in a cost effective manner.
- Energy Supply & Resource Development - manages the supply of natural gas and propane to customers, as well as managing energy resource planning, strategic project development, and major capacity initiatives.
- Customer Service – manages the interactions and relationships with customers.
- Energy Solutions & External Relations – manages external relations with communities, government bodies, and aboriginal and first nations groups, manages all internal and external communications including media and public relations, manages all support materials and publications, and plans and implements energy efficiency and conservation programs and new service offerings.
- Information Technology – manages all of the technology requirements in support of the business.
- Operations Engineering – manages the technical compliance with codes, standards and regulations.

- Operations Support – manages procurement, supply chain management, meter and measurement services, and communication and instrumentation systems.
- Facilities – manages all non-gas assets including buildings, property, security, space and furniture requirements as well as centralized office services.
- Human Resources – manages the overall workforce strategy, employee services, labour relations, compensation and benefits, recruiting, and employee development.
- Finance & Regulatory Affairs – manages the financial and regulatory reporting requirements.
- Corporate – provides overall management and leadership.

The table below shows the O&M (before capitalized overheads) for the years 2010 through 2013. O&M increases in the test period are 4.8 percent for each of 2012 and 2013.

Table 5.3-1: O&M Funding Reflects Our Continued Commitment to Safety and Integrity

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 206,464	$ 206,519	$ 214,680	$ 214,680	$ 224,119	$ 236,471
Vancouver Island	$ 31,229	$ 29,852	$ 32,702	$ 32,702	$ 35,236	$ 35,482
Whistler	$ 849	$ 773	$ 868	$ 868	$ 906	$ 915
Fort Nelson	$ 814	$ 794	$ 812	$ 812	$ 865	$ 897
Total	$ 239,356	$ 237,938	$ 249,063	$ 249,063	$ 261,127	$ 273,765

For 2012 and 2013, the O&M expenditure changes can be divided into five categories or cost drivers: labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability.

The following section will describe the five O&M cost drivers. Summary tables showing the incremental spending by cost driver for each of the departments for 2012 and 2013 is provided in Section 5.3.3. An overview of the changes in staffing levels is provided in Section 5.3.4. A description of changes on a department by department basis is provided in Sections 5.3.5 through 5.3.16. Capitalized overhead and corporate and shared services will also be discussed in Sections 5.3.17 and 5.3.18, respectively.

5.3.2 COST DRIVERS

5.3.2.1 Overview of Cost Drivers

O&M expenditures are influenced by a number of drivers with cost pressures coming from different sources including non-discretionary increases for inflation on internal labour and benefits, contracts and materials, increases in operating activities, and new business drivers and safety requirements. In particular, incremental funding requests are driven by five requirements – labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability. Each of these cost drivers is described in further detail in Sections 5.3.2.2 through 5.3.2.6 below.

Offsetting these incremental funding requests in 2012, the Companies are forecasting savings as compared to 2011 from the implementation of the HST and have included this reduction in O&M as a separate column in Tables 5.3-6, 5.3.8, 5.3.10 and 5.3.12 showing the changes from 2011 Approved to 2012 Forecast. This reduction amounts to $645 thousand[72] for the Mainland, $85 thousand for Vancouver Island, and $1 thousand for Whistler. A discussion of the ongoing uncertainty around the HST is included in Section 5.6 Taxes.

5.3.2.2 Labour Inflation and Benefits

Labour and benefit inflation are primarily non-discretionary costs required to fund expected wage and benefit increases for our employees. The total incremental funding in this category is summarized in the tables in Section 5.3.3. In all departments, the labour inflation and benefit loadings have been applied to the existing labour dollars from the prior year. Since this has been a consistent practice across all departments, the labour inflation category is not specifically addressed in each departmental discussion, but is instead included here as applicable to all departments.

In a labour market with increasing demographic challenges in certain areas, FEU must continually monitor and assess its Total Rewards[73] framework to ensure we remain competitive with respect to other employers, particularly utilities and others in the energy industry, that have a competing need for similar skill sets. The challenge is to find a balance where we are able to attract and retain talented people for key positions, while guarding against paying above market rates for other positions. FEU has defined a compensation philosophy of establishing our total

[72] The report "Terasen Utilities 2010-2011 Revenue Requirements – Impacts from Harmonized Sales Tax" showed $755 thousand for the Mainland area. The difference is $110 thousand related to the vehicle lease which is not included in O&M in this RRA.

[73] Total Rewards refers to all of the tools available to an employer that may be used to attract, motivate and retain employees. Total Rewards includes everything the employee perceives to be of value resulting from the employment relationship and may include:
Pay: Base Pay, Variable Pay, Long-term incentives;
Benefits: Health Care, Pension, Savings Plan, Time Off;
Learning & Development: Training, Career Development, Performance Management, Tuition Support;
Work Environment: Leadership, Values, Work/Life Balance, Organizational Climate, Community Involvement

cash compensation at the median of our defined peer group. Our total compensation core guiding principle is to deliver a total compensation program that includes employee understanding, administrative ease and cost controls that drive a perceived value which exceeds program costs. Paying competitive rates will allow FEU to attract the appropriate talent and help to retain employee knowledge in key areas of the Companies that are critical to the future success of the business. FEU needs to ensure that the Total Rewards cater to a diverse population and respond to the broad needs of a diverse workforce while retaining, attracting and motivating the talented individuals that FEU needs in order to continue to meet business goals and deliver service to our customers. The compensation philosophy of the FEU is discussed in Section 3.1.3.

The forecast O&M labour inflation and benefit increases for 2012 and 2013 are shown in the following table.

Table 5.3-2: O&M Labour and Benefit Increases for 2012 and 2013[74]

($ thousands)	2012			2013		
Utility/Region	**Labour Inflation**	**Benefits**	**Total for 2012**	**Labour Inflation**	**Benefits**	**Total for 2013**
Mainland *	2,160	(127)	2,033	2,507	1,266	3,774
Vancouver Island	152	(649)	(497)	140	4	144
Whistler	17	4	21	4	3	6
Total	**2,329**	**(772)**	**1,557**	**2,651**	**1,273**	**3,924**

* Fort Nelson - Labour Inflation and Benefits is included in Mainland and allocated and allocated to Fort Nelson

[redacted]

Redacted from Public Version

[74] The in-sourcing of the Customer Service department results in roughly 300 incremental employees. For this new employee group, 2012 is considered to be the base year, so that no incremental labour inflation or benefits are displayed for this department in that year in this table. Labour Inflation and benefit increases for the Customer Service group in the amount of $0.6 million is included in 2013.

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BENEFITS

For budgeting purposes, employee benefit costs are calculated and expressed as a percentage of total available employee labour dollars for determination of labour charge-out rates. In this fashion, increases in labour and benefits are allocated between O&M and capital, based on the chargeable hours forecast against O&M and capital activities. Within the O&M tables in this section, only the O&M portion of labour and benefit increases has been captured. The capital portion of the increases are captured in the capital expenditures found in Section 6.2.

Employee benefits include workers' compensation, long term disability, extended health and dental benefits, group life, Medical Services Plan, Canada Pension Plan, Employment Insurance, employee savings plans, employee incentive plans, share purchase plans, pension and other post employment benefits. Other than pensions, the benefit costs remain relatively unchanged from prior years. Due to their impact on total benefit costs and the changes being experienced, pensions and OPEBs are discussed further below.

The costs of providing all benefit programs are under pressure due to increasing health care costs and reduced funding by all levels of governments, and with a new generation entering the workforce, the costs associated with current pension and benefit programs may prove onerous, particularly for those early in their careers who prefer cash flow. Flexibility must be taken into consideration for pension and benefit design in order to ensure sustainability while meeting the needs of a multi-generational workforce. With the assistance of benefits consultants (Mercer[75]), benefits pricing is reviewed on an annual basis to ensure that our usage experience, pricing and the market are taken into consideration when determining the next years pricing model. New benefits options and products are explored and considered to ensure that our pricing remains as low as possible given the pressures that we face each year. In 2010, the Companies and the

[75] Mercer is a human resource and related financial services consulting firm, headquartered in New York City. The firm operates internationally in more than 40 countries, with more than 19,000 employees, and is the world's largest human resource consulting firm.

Unions explored options which helped to mitigate the contribution rate increases, and we will continue to explore methods to mitigate these in the future.

Valuation of the IBEW and COPE defined benefit pension plan was recently completed while valuation of the M&E defined benefit pension plan is in progress with results expected in May, 2011. Due to the 2008 financial sector crisis, competitive plan benefits, increasing liabilities and lower than anticipated plan investment returns, contribution rate increases are occurring for both the Companies and plan members. Plan contribution rates for both the Companies and plan members are as follows:

- For non-union employees, 7.5 percent of pensionable earnings effective October 1, 2010;
- For COPE and IBEW, 12.95 percent of plan earnings effective April 1, 2011.

These plan contribution rates are expected to remain in effect for a period of up to three years as the most recent actuarial valuations of the above noted plans were completed in late 2010 and early 2011. Actuarial valuations are only required to be completed every three years and the recently completed valuations are expected to be valid until late 2013.

Pension and OPEB expenses are based upon actuarial estimates provided by the Company's actuaries, Towers Watson and Morneau Sobeco. Both firms have provided actuarial services to FEU for more than ten years and are very knowledgeable about FEU's pension plans and actuarial forecasting. For regulatory purposes, pension and OPEB expense forecasts for 2012 and 2013 have been prepared using the existing approved IFRS accounting methodologies assuming a transition date of January 1, 2010.

- For the Mainland, the actuarial estimates for pension and OPEB costs, excluding pension and OPEB for the incremental employees in the Customer Service department, are $12.1 million for 2012 and $12.0 million for 2013. A pro-rata share is allocated to Fort Nelson.
- Actuarial estimates of the pension and OPEB costs for the incremental employees in the Customer Service department are $0.4 million for 2012 and $0.4 million for 2013.
- For Vancouver Island, the actuarial estimates for pension and OPEB costs are $1.4 million for 2012 and $1.4 million for 2013 with a pro-rata share being allocated to Whistler.

These actuarial estimates do not translate directly into O&M expenses because a portion of the pension and OPEB expenses are capitalized. Pension and OPEB expenses are apportioned into two components, a current service component and a net benefit expense which includes the current service component not capitalized. The current service component is included in labour loadings and therefore in both O&M and capital expenditures, consistent with the treatment approved in the 2010-2011 RRA. The past service cost component is included in O&M only, as these costs have already vested.

- For FEI in 2012, the pension and OPEB costs are forecast to increase $1.1 million over 2011. This consists of an increase to the current service component of $3.9 million, offset by a reduction to the past service component of $2.8 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2012 is a reduction of $0.7 million. For FEI in 2013, the Pension and OPEB costs are forecast to decrease $0.1 million over 2012. This consists of an increase to the current service component of $0.4 million, offset by a reduction to the past service component of $0.5 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2013 is a reduction of $0.2 million.
- For FEVI in 2012, the pension and OPEB costs are forecast to decrease $0.4 million over 2011. This consists of an increase to the current service component of $0.2 million, offset by a reduction to the past service component of $0.7 million. After the allocation of the current service component to capital and deferrals, the net impact to O&M in 2012 is a reduction of $0.6 million. For FEVI in 2013, the pension and OPEB costs are forecast to decrease $0.1 million over 2012. This consists of a marginal increase to the current service component, offset by a marginal reduction to the past service component. The net impact to O&M in 2013 is a reduction of $0.1 million.

With respect to accounting treatment, we have prepared the O&M, capital and deferral estimates included in this RRA, including Pension and OPEB expenses, under the IFRS scenario in 2012 and 2013. This is consistent with FEU's calculation of pension and OPEB estimates for 2011, which was done as a result of the requirement to adopt IFRS by January 1, 2011 at the time of filing the 2010-2011 Revenue Requirements. (Prior to that date, we had calculated pension and OPEB estimates under Canadian GAAP.) The FEU have since applied for approval from the Commission to adopt US GAAP for regulatory purposes. In Section 3.2, the FEU discuss the impacts on this RRA of adopting US GAAP as compared to IFRS with deferral accounts, and included in that section are the estimated pension and OPEB costs under US GAAP.

5.3.2.3 Codes and Regulations

Codes and Regulations funding requirements are driven by the Companies' need to comply with existing codes and regulations as well as anticipated new or changed codes and regulations. The UCA, *Oil and Gas Commission Act*, *Workers' Compensation Act*, *Environmental Management Act*, *Safety Standards Act*, fire codes and safety standards, Provincial and Federal Emergency Acts, and Canada Standards Association Codes are some of the key codes and legislation with which the Company must be in compliance. These, along with other legislation, regulations, and bylaws, define FEU's level of reporting and compliance activities. These activities have a strong focus on public, employee, property, and environmental safety, and system reliability. A variety of external agencies oversees the Companies' response to these codes and regulations, to which FEU has a solid track record of compliance. Key applicable codes and regulations are outlined in Table 5.3-3 below.

Table 5.3-3: Codes and Regulations that Impact FEU Business

Code/Regulation/Standard	Governing Body
B.C. Environmental Management Act	B.C. Ministry of Environment
BC Safety Standards Act and Gas Safety Regulations	B.C. Safety Authority
Power Engineers and Boiler and Pressure Vessel Safety Act	B.C. Safety Authority: Pressure Vessels branch
B.C. Pipeline Act and Oil & Gas Commission Act (being replaced by Oil & Gas Activities act)	B.C. Oil & Gas Commission
CSA Z276: Liquid Natural Gas Production, Storage and Handling	Canadian Standards Association B.C. Oil & Gas Commission
CSA Z246: Security Management for Petroleum and Natural Gas Industry Systems (anticipated release October 2009)	Canadian Standards Association B.C. Oil & Gas Commission
CSA Z662 – Oil and Gas Pipeline Systems Including: • Clause 10.2 Safety & Loss Management System (annex A –framework) • Annex M: Gas distribution integrity management guidelines • Annex N: Guidelines for pipeline integrity management programs	Canadian Standards Association B.C. Oil & Gas Commission B.C. Safety Authority Workers' Compensation Board of BC
Electricity and Gas Inspection Act & Inspection regulations	Measurement Canada
WorkSafeBC Occupational Health & Safety Regulation • CSA Z1000 Safety Management System (framework)	Workers' Compensation Board of BC
Others including: • Provincial and Federal Emergency Acts; • Fire codes; • Building codes; • Emissions permits; and • Municipal and regional bylaws.	Various

For each of these codes and regulations, the Company has implemented management systems and/or operating practices to ensure compliance. The total incremental funding in this category is summarized in the tables in Section 5.3.3. Specific requirements to address compliance with Codes and Regulations are included later within each department's discussion, along with a reference to the specific code or regulation.

5.3.2.4 Customer and Stakeholder Expectations

O&M expenses in this category are primarily due to:

- recent BCUC decisions approving the in-sourcing of our Customer Service function;
- the Biomethane Program and the interim decision and ongoing review process for natural gas for CNG and LNG fueling infrastructure;
- funding support to meet increased regulatory requirements and customer expectations around long-term resource planning; and
- participant funding and BCUC direct costs for the regulatory process.

The total incremental funding in this category is summarized in the tables in Section 5.3.3. The incremental O&M increases in this category are addressed later on a department-by-department basis along with a reference to the relevant BCUC decision if applicable.

5.3.2.5 Demographics

The demographic challenges presented by the FortisBC Energy Utilities' aging workforce require increased efforts to proactively recruit, train and develop, transition, and manage overall changes to the composition of the workforce in the coming years. Shifting workforce demographics has been a well-known reality for some time and continues to be a major source of concern for governments and businesses alike. The initial wave of baby boomers has reached retirement age and the number of workers in British Columbia retiring each year is expected to swell from 56,000 to over 62,000 over the next decade[77]. As this scenario unfolds, the long predicted labour shortages, particularly within the skilled and professional trades, will begin to materialize. The combination of an aging population, declining birth rates, and continued economic growth will create significant pressure on businesses and available labour supply. As stated in the Ministry of Regional and Economic Skills Development British Columbia's Labour Market Strategy to 2020:

> *"As a result of economic growth, employment in British Columbia is expected to grow by an average of 1.8 percent each year through to 2019, creating a total of 450,000 new jobs. Approximately 676,000 additional jobs will become vacant due to retirements. In total, there will be an expected 1,126,000 job openings over the next decade. There are about 650,000 young people in our education system today which means that the growth in job openings is expected to outpace the number of workers."*[78]

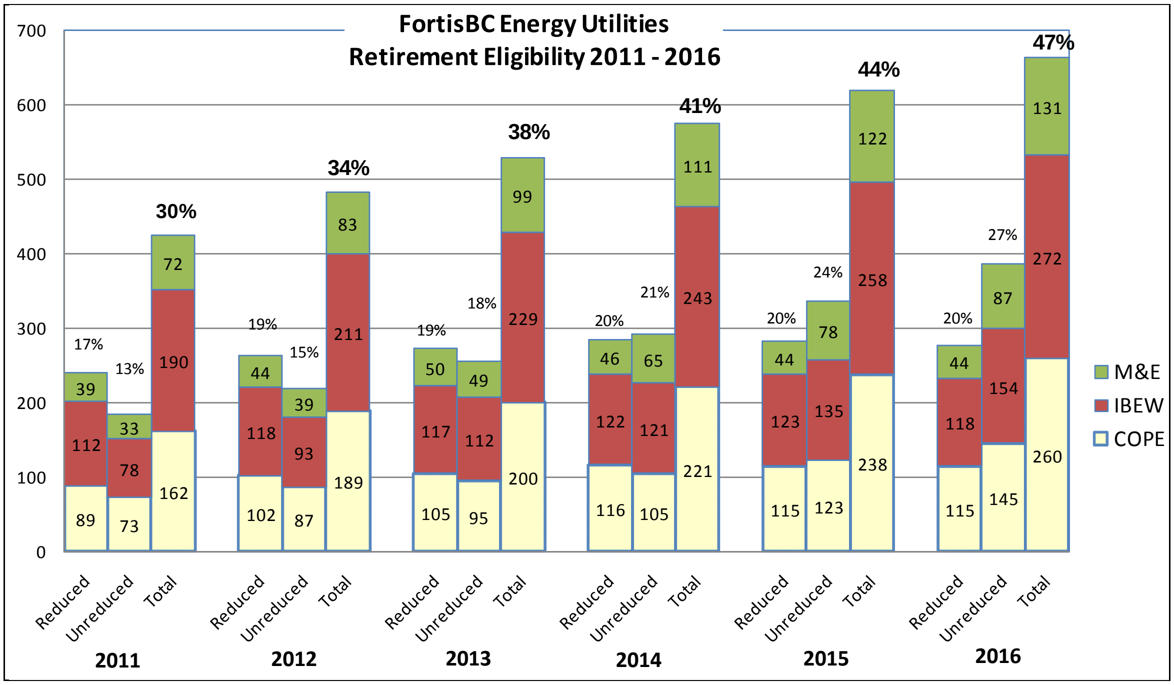
Like many other organizations faced with an aging workforce and a shrinking labour market, FEU faces the challenge of having approximately half of its current workforce eligible to retire in

[77] Skills for Growth: British Columbia's Labour Market Strategy to 2020; Ministry of Regional and Economic Skills Development, Page 5

[78] Ibid

the next five years. In fact, between 2011 and 2016, a total of 663 FEU employees will become eligible to retire; 386 of those will be eligible to retire with an unreduced pension. This information is displayed in Table 5.3-4 below.

Table 5.3-4: Large Numbers of Employees Eligible to Retire Within 5 Years



	2011			2012			2013			2014			2015			2016		
	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total	Reduced	Unreduced	Total
COPE	89	73	162	102	87	189	105	95	200	116	105	221	115	123	238	115	145	260
IBEW	112	78	190	118	93	211	117	112	229	122	121	243	123	135	258	118	154	272
M&E	39	33	72	44	39	83	50	49	99	46	65	111	44	78	122	44	87	131
Total	**240**	**184**	**424**	**264**	**219**	**483**	**272**	**256**	**528**	**284**	**291**	**575**	**282**	**336**	**618**	**277**	**386**	**663**

The following Table 5.3-5 provides the number of employees eligible to retire with an unreduced pension within specific departments over the next five years.

Table 5.3-5: Retirement Risk Varies by Department

Employees Eligible to Retire (With Unreduced Pension) by Department						
DEPARTMENT	**2011**	**2011-2012**	**2011-2013**	**2011-2014**	**2011-2015**	**2011-2016**
Customer Service	2	2	2	3	5	6
Distribution	90	105	127	143	160	183
Energy Solutions & External Relations	7	9	10	11	16	19
Energy Supply & Resource Development	2	2	3	4	4	5
Facilities	4	6	6	6	6	7
Finance & Regulatory Affairs	6	9	12	13	15	17
Human Resources	5	7	8	10	11	12
Information Technology	4	5	6	8	11	13
Operations Engineering	34	38	40	42	46	55
Operations Support	14	19	20	26	32	36
Corporate				1	1	1
Transmission	16	17	22	24	29	32
Grand Total	**184**	**219**	**256**	**291**	**336**	**386**
* Note: Eligibility shown in the table is cumulative year over year						

The two groups facing the most significant retirement risk are Distribution and Transmission, where a total of 122 employees are eligible to retire with unreduced pensions in 2012, or 16 percent of their total combined workforce. This accounts for 56 percent of the 219 employees overall in all groups who will be eligible to retire in that year. Many of these employees are in highly technical or specialized field positions which require higher skill levels, are difficult to recruit and therefore demand longer training and knowledge transfer periods. In addition, more than 40 percent of Distribution managers are eligible to retire with reduced or unreduced pensions in 2012 which presents significant additional knowledge and experience loss. These workforce challenges are creating increased demand for field training as well as management and leadership development.

A few other departments such as Operations Engineering and Operations Support are also facing higher than average retirement risk, but the impact on their day-to-day operations is not of the same magnitude as the risk faced by Distribution and Transmission, and those departments should be able to manage the risk within their existing workforce plans.

The increased demand for training, employee development and knowledge transfer resulting from the large number of retirements, and related hiring of replacement employees, is having a direct impact on the Human Resources department which, as outlined in Section 5.3.13.4, will require additional O&M in 2012 in order to meet this challenge. Human Resources must continue to work closely with department managers to develop new plans and strategies to mitigate these risks, including:

- Developing effective workforce plans, recruiting and training strategies to manage the demographic risk;
- Providing effective and timely delivery of competency based peer training for large numbers of new hires (i.e. entry level Distribution Apprentices) accompanied by

thorough documentation of procedures and training materials to ensure compliance with code requirements;

- Continued evolution and sustainment of the competency management program beyond field employees;
- Providing management and leadership training to ensure there is sufficient, skilled management and leadership capacity in place to meet business needs; and
- Developing innovative and more efficient means for design and delivery of training, such as E-learning.

The total incremental funding in this category is summarized in the tables in Section 5.3.3. The incremental O&M increases in this category are addressed later on a department-by-department basis.

5.3.2.6 Service Standards and Reliability

The Service Standards and Reliability category includes any other required costs to support the ongoing integrity of our systems, and increases in non-labour costs including contractual funding increases for price escalation of existing contracts and service agreements. Please see Sections 1 and 6.2 for a detailed discussion of our system integrity focus through our Long-term Sustainment Plan and our commitment to ensure the safety and integrity of our delivery systems.

The total incremental funding in this category is summarized in the tables in Section 5.3.3. The incremental O&M increases in this category are addressed later on a department-by-department basis.

5.3.3 SUMMARY OF FORECAST 2012 & 2013 OPERATING COSTS (DEPARTMENTAL OVERVIEW)

The following tables reconcile the O&M incremental funding for 2012 and 2013 by category and by department. Many of the Mainland departments do not have direct O&M in Vancouver Island, Whistler and Fort Nelson. In these cases, the appropriate allocation of costs to those regions is included in the Corporate Department as a Shared Services fee. A discussion of both Shared Services and Corporate Services is included in Section 5.3.18.

Table 5.3-6: Mainland 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	43,153	(54)	1,738	120	-	160	2,520	4,485	47,638
Transmission	14,994	(57)	244	(130)	133	91	1,005	1,287	16,280
Energy Supply & Resource Development	3,748	(14)	125	-	-	-	84	195	3,943
Customer Service	56,935	(15)	120	-	(1,653)	-	-	(1,548)	55,388
Energy Solution & External Relations	14,370	(4)	606	750	1,616	-	85	3,054	17,423
Information Technology	20,095	(185)	233	4	-	-	1,358	1,410	21,505
Operations Engineering	13,288	(122)	326	533	-	(190)	242	788	14,076
Operations Support	9,847	(91)	675	352	67	-	387	1,391	11,238
Facilities	6,201	(57)	24	-	-	-	262	228	6,430
Human Resources	8,280	(14)	265	59	-	313	65	687	8,966
Environmental & Safety	2,615	(5)	76	50	36	-	121	278	2,893
Finance and Regulatory	9,953	(1)	417	-	640	-	62	1,118	11,071
Corporate	11,201	(27)	(2,817)	-	-	-	(1,091)	(3,935)	7,266
Total	214,680	(645)	2,033	1,738	839	374	5,100	9,439	224,119

Table 5.3-7: Mainland 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	47,638	-	1,307	600	-	270	1,243	3,420	51,058
Transmission	16,280	-	185	(75)	106	(46)	1,048	1,218	17,499
Energy Supply & Resource Development	3,943	-	99	-	-	-	154	253	4,196
Customer Service	55,388	-	553	-	3,018	-	-	3,571	58,959
Energy Solution & External Relations	17,423	-	489	100	299	-	128	1,015	18,439
Information Technology	21,505	-	290	-	-	-	475	765	22,270
Operations Engineering	14,076	-	378	44	-	-	135	557	14,633
Operations Support	11,238	-	252	65	10	-	237	564	11,802
Facilities	6,430	-	62	-	-	-	(139)	(77)	6,353
Human Resources	8,966	-	265	-	-	-	151	416	9,382
Environmental & Safety	2,893	-	52	35	50	-	27	164	3,057
Finance and Regulatory	11,071	-	328	-	-	-	-	328	11,399
Corporate	7,266	-	(485)	-	-	-	643	158	7,424
Total	224,119	-	3,774	769	3,483	224	4,103	12,353	236,471

Table 5.3-8: Vancouver Island 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	5,379	(31)	87	-	-	-	353	409	5,787
Transmission	6,134	(41)	62	(92)	-	-	693	621	6,755
Energy Supply & Resource Development	100	-	-	-	-	-	-	-	100
Customer Service	5,459	(3)	-	-	(198)	-	-	(201)	5,257
Energy Solution & External Relations	1,464	(1)	37	150	-	-	7	193	1,657
Information Technology	421	(0)	1	-	-	-	-	1	422
Operations Engineering	679	(2)	-	-	-	-	-	(2)	677
Facilities	1,618	(5)	-	-	-	-	(150)	(155)	1,463
Finance and Regulatory	383	(0)	-	-	110	-	-	110	493
Corporate	11,065	(1)	(684)	-	-	-	2,245	1,560	12,625
Total	32,702	(85)	(497)	58	(88)	-	3,147	2,534	35,236

Table 5.3-9: Vancouver Island 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Year End Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	5,787	-	139	40	-	-	402	582	6,369
Transmission	6,755	-	63	45	-	-	201	308	7,064
Energy Supply & Resource Development	100	-	-	-	-	-	-	-	100
Customer Service	5,257	-	-	-	342	-	-	342	5,599
Energy Solution & External Relations	1,657	-	30	-	-	-	7	37	1,694
Information Technology	422	-	4	-	-	-	-	4	426
Operations Engineering	677	-	-	-	-	-	-	-	677
Facilities	1,463	-	-	-	-	-	(924)	(924)	539
Finance and Regulatory	493	-	-	-	-	-	-	-	493
Corporate	12,625	-	(92)	-	-	-	(11)	(103)	12,522
Total	35,236	-	144	85	342	-	(325)	246	35,482

Table 5.3-10: Whistler 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	451	-	21	-	-	-	(42)	(21)	430
Customer Service	156	-	-	-	(10)	-	-	(10)	146
Corporate	261	(1)	-	-	-	-	70	69	330
Total	868	(1)	21	-	(10)	-	29	38	906

Table 5.3-11: Whistler 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	430	-	6	-	-	-	(6)	(0)	430
Customer Service	146	-	-	-	8	-	-	8	154
Corporate	330	-	-	-	-	-	1	1	331
Total	906	-	6	-	8	-	(6)	9	915

Table 5.3-12: Fort Nelson 2012 Incremental Funding

Department (Amounts in $ Thousands)	2011 Projection	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations *	Demographics	Service Standards & Reliability	Total Incremental	Total 2012 Forecast
Distribution	347	-	-	-	-	-	(4)	(4)	344
Customer Service	136	-	-	-	(136)	-		(136)	-
Corporate	329	-	-	-	-	-	193	193	522
Total	812	-	-	-	(136)	-	189	53	865

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

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Table 5.3-13: Fort Nelson 2013 Incremental Funding

Department (Amounts in $ Thousands)	2012 Forecast	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total 2013 Forecast
Distribution	344	-	-	-	-	-	7	7	350
Corporate	522	-	-	-	-	-	25	25	547
Total	865	-	-	-	-	-	31	31	897

5.3.4 EMPLOYEES

FEU will be increasing its staffing levels over the forecast period, driven primarily by the in-sourcing of Customer Service functions. Table 5.3-14 below provides the forecast employee levels for the 2012 and 2013 periods with the most recent years (2010 and 2011) included for comparison. Similar tables along with explanations for changes year over year are also provided for each department in their respective sections.

Not all the employees and their associated labour hours and dollars are for support of O&M activities. To provide clarity regarding the employee distribution, the employees have been allocated between O&M, Capital and Deferral activities (i.e. EEC programs).

Table 5.3-14: Growing Employees to Support In-Sourced Customer Service and Enhanced Reliability[79]

SUMMARY
Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	1,294	1,316	1,311	1,692	1,701	1,701
Vancouver Island	111	107	122	124	123	124
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,411	1,427	1,438	1,821	1,828	1,829

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	298	286	287	671	358	358
Vancouver Island	39	31	40	45	42	42
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	337	317	327	716	400	400

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	996	1,029	1,024	1,021	1,343	1,343
Vancouver Island	72	77	82	79	81	82
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	1,074	1,110	1,111	1,105	1,428	1,429
Dependant Contractors excluded	23	15	23	3	3	3

The requirements driving the overall employee numbers are described in each of the individual department discussions in Sections 5.3.5 through to 5.3.16.

The 2010 Approved and Actual, and the 2011 Approved employees listed in Table 5.3-14 above do not include any employees hired into the Customer Service Department as a result of the approval of the Customer Care Enhancements Certificate of Public Convenience and Necessity ("CPCN") Project (the "CCE Project"). The Customer Service department accounts for 331 of

79 Employees in this Section are the number of Full Time Equivalent employees as at December 31. Starting in 2011, dependant contractors have been mostly replaced by employees, reducing their numbers from 23 to 3 with an offsetting increase in Capital and O&M employees, as shown in the 2011 Projection. The dependant contractors are all IBEW; this change in status is more fully explained in the Operations O&M Section 5.3.5

the forecast increase in total employees included in the 2011 Projection; in 2011 their costs are included in the Deferral account for the CCE Project. For 2012 and 2013, the increased Customer Service department employees are primarily included in the O&M category. Further discussion of the Customer Service department employee requirements is included in the Customer Service O&M Section 5.3.7.

High-level departmental organization charts are included in each of the departmental overviews in Sections 5.3.5 through 5.3.15. Detailed company-wide organization charts are included in Appendix H.

5.3.5 OPERATIONS (DISTRIBUTION AND TRANSMISSION)

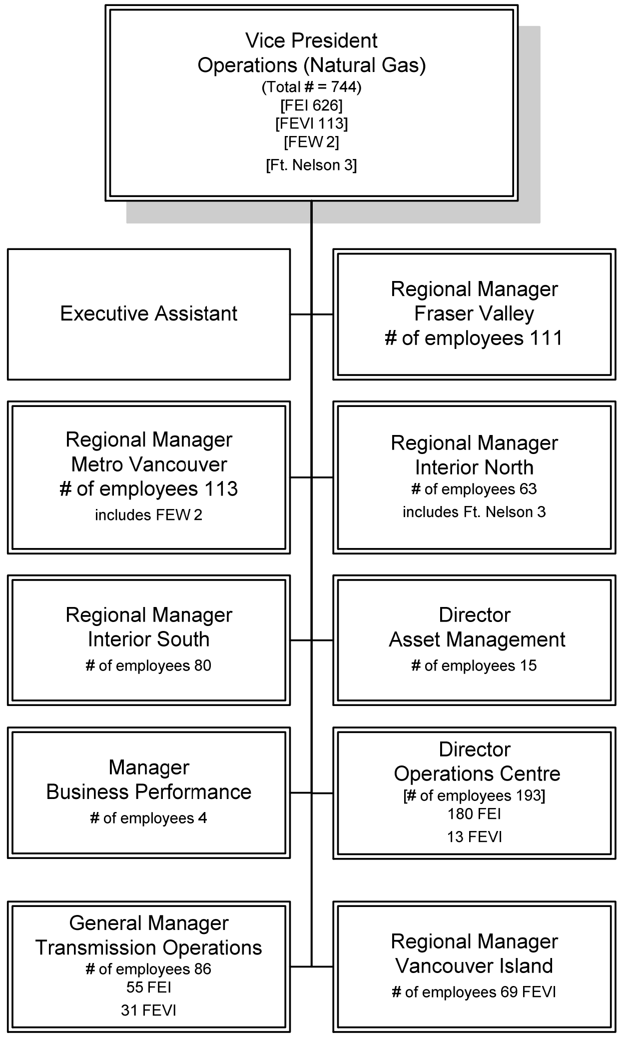
This section will provide a detailed review of the forecast O&M for the Operations Department (which include Distribution and Transmission). The section will proceed as follows:

- Departmental overview;
- Distribution O&M Expenditures and Employees;
- Distribution 2010 and 2011 Review;
- Distribution 2012 and 2013 Forecast;
- Transmission O&M Expenditures and Employees;
- Transmission 2010 and 2011 Review; and
- Transmission 2012 and 2013 Forecast.

5.3.5.1 Departmental Overview

In early 2011, the Distribution and Transmission groups were combined to create the Operations department which reports to the Vice President, Operations (Natural Gas). Operations is the largest department in terms of number of employees, budget and geographical footprint, and plays a major role in prudently managing O&M and capital expenditures. The Operations department is comprised of three main functional groups, Asset Management, Distribution, and Transmission. Each will be discussed below. The organization of the Operations Department is shown in the chart below.

Figure 5.3-1: Organization Chart for Operations



ASSET MANAGEMENT

The Asset Management group provides planning and management oversight of the installation, operation, and maintenance of the Company's distribution and transmission gas system assets. The group provides information gathering and analysis to achieve a holistic view of asset management, and is responsible for the development and continuous improvement of maintenance and capital programs that ensure ongoing safe, reliable, and cost effective service. In support of these responsibilities, the Asset Management group adopts and develops improved asset management practices that underpin its ability to maintain system reliability, safety, and regulatory compliance. Although Asset Management focuses largely on management of existing gas system assets, in the future it will increasingly need to manage new assets that are required to support such services as those offered through the natural gas vehicle ("NGV") and biomethane programs.

The need for effective system sustainment is a key asset management issue that is addressed in this Application. Improving the Company's asset management practices is becoming increasingly important so that the reliability and safety of the distribution and transmission system is sustained as it ages. This management is also important in order to ensure that any changes are cost effective and that their impact on customers' rates is kept to a minimum. The incremental O&M and Capital costs driven by system sustainment are reviewed in later sections of this Application.

In order to better support the Companies' ability to continue to improve asset management practices, a single Asset Management group for distribution and transmission assets was formed earlier this year as part of the organizational change. Previously, asset management focussed on a short, one to five year, planning horizon. A single management view of distribution and transmission assets will allow FEU to take a longer term view of system sustainment in order to more effectively address issues such as: the age of FEU's infrastructure; ongoing compliance to existing codes and anticipated new or changed codes; and customer, public and stakeholder expectations. Going forward, Asset Management will view the assets as a whole and will be better able to conduct system sustainment assessments, bring together local knowledge and experience, and improve formal asset health reports in order to identify areas of potential concern (i.e. single points of failure, lack of redundancy of supply). These areas must then be examined in more detail to determine whether operating and maintenance practices need to change or if additional capital expenditures are warranted. These initial assessments, which engage both internal and external expertise, are key to making appropriate long-term system sustainment decisions.

Incremental O&M funding is required to conduct system sustainment assessment as described below to enable the further development of the Company's asset management practices. Failure to adequately fund these assessments will limit the ability to develop the management systems needed to support a long term asset management view. Current resources are insufficient to complete the considerable reviews and analysis that are required to support future capital expenditure commitments in the amounts anticipated. If the budget requests are approved, Asset Management will secure the necessary resources needed to improve the management of asset renewal and refurbishment requirements, and to develop a more detailed, longer planning horizon.

DISTRIBUTION

The Distribution group is responsible for installing, operating and maintaining the gas distribution system, and providing safe, reliable and cost effective service directly to gas customers. Field personnel are trained and equipped with tools, equipment and vehicles to provide emergency response, operate and maintain the gas distribution system and to perform installations and renewals.

Distribution field and office activities are a combination of emergency response, operations and maintenance, and capital programs, and the group is organized to maximize synergies when completing the various installation, operational, and maintenance activities. The activities within Distribution are organized into four main functions or business processes - Emergency Management, Installation and Renewal, Operations and Maintenance, and Account Services. Additionally, Centralized Support Services, located in the Company's main operations centre in Surrey, is responsible for planning, resource management, dispatching and closing. These functional areas are described in greater detail below.

EMERGENCY MANAGEMENT

Emergency Management includes providing first and rapid response in order to ensure public, asset and employee safety. The activities include first response to system damage, gas odours, fire and carbon monoxide calls, emergency prevention through public education, and maintaining stand-by resources. Emergency response personnel and resources are mustered throughout FEU's service area to provide timely response to emergencies.

INSTALLATION AND RENEWAL

Installations include new mains, services, meters, stations and projects required to add customers and improve system reliability, integrity and capacity. Renewals are essentially replacements of the gas system components generally due to age, technology and obsolescence. Although employees routinely perform these activities, a significant portion of installation and renewal activity is performed by external contractors, particularly during periods of high customer additions activities.

OPERATIONS AND MAINTENANCE

Operations and Maintenance includes scheduled and unscheduled operating and maintenance activities dedicated to mitigating operating risks and ensuring the safety and reliability of the distribution system. Activities include system inspection, leak survey, preventive and corrective maintenance of equipment, valves, stations and meter sets. The level of activity required is influenced by code and standard requirements (i.e. Canadian Standards Association ("CSA")), regulatory requirements, operating and asset conditions.

ACCOUNT SERVICES

Account Services work performed by Distribution staff includes premise calls, meter lock-offs, unlocks and reactivations, meter exchanges/renewals and other customer inquiries requiring a field workforce response. An example of this is a high bill complaint initiated by a customer which results in a visit to the customer's premise to ensure the meter is functioning correctly.

CENTRALIZED SUPPORT SERVICES

In addition to Asset Management, there are two centralized Distribution support groups located primarily in Surrey: Process Support and the Operations Centre. The support groups provide the necessary expertise to assess work priorities, plan and design work to be completed, establish and maintain processes to be followed, and coordinate who, when and how the work gets completed. They also monitor costs and operational metrics to ensure commitments made to customers, regulators and other stakeholders are met.

TRANSMISSION

The Transmission group is responsible for ensuring the transmission system delivers natural gas from interconnecting pipelines, or Company owned liquefied natural gas ("LNG") facilities, to the distribution network and for operating and maintaining the mainline pipelines, compressor stations and LNG plants in a safe, reliable and cost effective manner.

Transmission operates and maintains a range of critical assets, falling into three main categories: pipelines, compressor stations, and LNG Plants. The assets operated by the group include the Interior Transmission system mainline, the Southern Crossing Pipeline, the Coastal Transmission system, the Island Transmission system, a number of transmission pressure lateral pipelines and marine loops, mainline compressor stations, and LNG plants at Tilbury and Mt. Hayes.

The Transmission group is organized based on specialized skills for three main types of assets. Field personnel are trained and equipped with tools, equipment and vehicles to provide emergency response, operate and maintain the transmission system and complete system improvements.

5.3.5.2 Distribution O&M Expenditures and Employees

To continue to meet the functions and objectives identified above, the Distribution group requires the forecast expenditures and headcount for the 2012 and 2013 test years as outlined in this RRA and shown in Tables 5.3-15 and 5.3-16 below. The Companies believe these forecast expenditures are reasonable and prudent, and consistent with expenditure levels observed in recent years.

Table 5.3-15: Distribution O&M Forecast to Meet Future Requirements

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 40,438	$ 41,887	$ 43,153	$ 43,153	$ 47,638	$ 51,058
Vancouver Island	$ 5,626	$ 5,238	$ 5,379	$ 5,379	$ 5,787	$ 6,369
Whistler	$ 446	$ 383	$ 451	$ 451	$ 430	$ 430
Fort Nelson	$ 359	$ 338	$ 347	$ 347	$ 344	$ 350
Total	$ 46,869	$ 47,846	$ 49,330	$ 49,330	$ 54,198	$ 58,207

Table 5.3-16: Distribution Employees to Meet Future Requirements

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	536	519	539	571	577	586
Vancouver Island	80	72	80	82	79	79
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	622	595	624	658	661	670

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	176	153	162	201	195	197
Vancouver Island	39	31	39	44	41	41
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	215	184	201	245	236	238

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	360	367	377	370	382	389
Vancouver Island	41	41	41	38	38	38
Whistler	3	1	2	2	2	2
Fort Nelson	3	3	3	3	3	3
Total	407	411	423	413	425	432

For a discussion of the Distribution capital expenditures, please refer to Section 6.2.

DISTRIBUTION EMPLOYEES

Distribution has 89 percent of the actual Operations employees in 2010, consisting of IBEW, COPE and M&E resources. These resources are required to manage, initiate, plan, schedule, dispatch, complete, and close field work. Distribution field personnel and resources are mustered throughout the service territory to provide timely response to emergencies and provide resources for routine utility activities. Regular O&M programs and activities are primarily completed by FEU employees, with approximately 7 percent of O&M programs completed by contractors/consultants. Approximately 35 percent of FEU employees are also utilized to complete capital work which is primarily a result of being able to utilize emergency response resources on smaller capital jobs at times when resources are available. FEU employees are also used on capital installations when unique skills unavailable in the open market are required or where the risk associated with the work requires it be done by experienced FEU personnel (i.e. System Operations Technicians commissioning a new station, crews completing large or complex pipeline tie-ins).

The 2010 actual employees are lower than the 2010 approved because of the large number of retirements. There were 33 IBEW retirements in 2010 which were at least partially triggered by changes to post retirement benefits effective January 1, 2011. The 2010 workload was managed by focusing FEU personnel on O&M activities and the installation contractor on capital activities.

In the 2011 projection for the Mainland, the principal reason for the increase in employee headcount has been the conversion of twenty long-time dependent IBEW contractor backhoe positions (not included in the employee numbers) to regular IBEW equipment operator positions (included in the employee numbers). This strategy was undertaken to increase the flexibility and efficiency of the crews. There were also ten additional planners and appointment setting employee positions added to the Operations Centre to support capital programs including third party alteration work, the hazard mitigation program and the inactive services program.

Due to the fact that certain positions in Distribution move between O&M and capital activities, the employee split between O&M and Capital is an estimate based on the following methodology. First, to arrive at the employee number for O&M, the wage/salary portion of the Distribution O&M was divided by the average Distribution salary to arrive at an estimated O&M related employee count. Second, the remaining headcount is categorized as Capital/Deferral. The methodology was applied consistently in the Distribution employee table for the 2010-2013 period.

DISTRIBUTION CONTRACTORS/CONSULTANTS

In addition to the FEU employees identified above, Distribution also utilizes contractors. The volume of capital and O&M work completed by contractors varies from year to year, depending on the overall capital workload, the level of regular operating and maintenance work, the number and size of emergencies and the number of vacancies in Distribution.

FEU periodically engages contractors and consultants for completion of Distribution O&M work activities. These resources are required to supplement the regular FEU employees in areas where in-house expertise is unavailable, the resource is a temporary requirement, and/or it makes economic sense to outsource. The most significant categories of contractor usage are in the areas of leak survey, flagging (i.e. to support emergency response, leak and valve repairs), vegetation clearing, paving and bridge crossing inspections and repairs. The most significant categories of consultant usage are in the areas of planning, seismic and customer satisfaction studies. In 2010 and 2011, the contractor/consultant employee equivalent embedded in Distribution O&M budgets is approximately 45 employees.

In addition to the FEU employees summarized in the tables and the contractor/consultants identified for O&M work activities above, there is a significant secondary workforce consisting primarily of two major installation contractors and a host of tertiary contractors (paving, flagging, project management, etc.). They provide a peak shaving resource for the capital workload which is more seasonal and unpredictable than regular O&M work and are an integral part of completing the capital work plans including new customer attachments (mains and services), system reliability and integrity projects and other major projects. In 2010, 82 percent of new mains work activity and 40 percent of new service work were completed by installation contractors. In addition, almost all larger project work such as system improvements are completed by contractors.

5.3.5.3 Distribution 2010 and 2011 Review - Mainland

2010 ACTUAL VERSUS 2010 ALLOWED

Distribution incurred O&M expenditures prudently to operate the gas distribution systems as outlined in the 2010-2011 RRA and met its program commitments. However, in doing so, it was $1.45 million or 3.6 percent over-budget in 2010. The principal reasons the 2010 actual varied from the 2010 allowed amount are as follows:

- System Damage Provisions ($400 thousand) – Several unusually large (>$100 thousand) third party damage repairs were incurred in 2010, and to date FEU has been unable to collect from the damagers for the repairs. FEU has made a provision for bad debt, but continues to negotiate with the damager and/or the damager's insurer. Partial recovery is expected in some future year, although legal costs to pursue recovery will negate much of the recovery. While we have limited experience with claims in excess of $100 thousand, the partial recovery is expected to be protracted (between one and five years if resolved through the courts). The size and frequency of significant third party damage events is at least partially attributable to the sizeable infrastructure projects undertaken by provincial and municipal governments in 2010 as they take advantage of funding available under the Federal Action Plan, the economic recovery plan put in place by the federal government to address the 2008 - 2009 economic downturn. FEU has increased its efforts to conduct damage prevention workshops in targeted municipalities with the support and assistance of WorkSafeBC and the BC Safety Authority in an effort to prevent these damages from occurring.

- S301HP Regulator Repairs ($400 thousand) – Distribution identified a significant unexpected performance issue in mid-2010 with a type of regulator (S301HP) used in gas service to commercial customers that required immediate resolution to ensure customer safety and reliability. The regulator performance issue, once identified, affected approximately 3,200 commercial class customers. This was a one-time unusual repair program requiring immediate resolution. FEU worked with manufacturer representatives in identifying a malfunctioning part in the S301HP regulator, obtaining replacement parts and developing a repair procedure. Replacement parts were supplied by the manufacturer; however, labour used to make the repairs was not covered by warranty.

- Leak Repairs ($375 thousand) – The number and magnitude of leak repairs is somewhat unpredictable from year to year with the unit cost varying from $1,000 to $100 thousand depending on the location, difficulty to locate, repair methodology and conditions, response effort, etc. 2010 was an atypical year in terms of overall spending levels for leak repairs. While activity levels remained consistent with prior years, average unit costs increased from $2,100 to $2,700 per repair. The average unit cost increase was due primarily to one significant leak repair (Como Lake Road-Coquitlam Intermediate Pressure line, $73 thousand) together with the impact of having new Distribution Apprentices on each of the repair crews.

- IBEW Training ($275 thousand) – In 2010, there were 53 new Distribution field hires and 132 field employees in new positions, which is considerably higher than previous years. This increase was driven by the high number of retirements (33) in 2010 which was influenced by changes to post retirement benefit packages beginning in 2011. The Distribution field workforce continues to face demographic challenges. Fifty four (or 14 percent of) IBEW field employees are eligible for retirement today and we have responded to this challenge through an apprentice program. While typically Distribution field employees are provided with 10 to 14 days of classroom training per year inclusive of travel to and from training sites, the Distribution Apprentice ("DA") program currently includes 45 days of classroom training during the first two years. The hiring of DAs (39 in 2010) created pressures on the training budgets. Furthermore, the significant number of retirements in the more highly technical field positions (System Operations Technicians, Customer Service Technicians, etc.) also generated significant training pressures as their replacements filled these roles.

- Operations Centre ($335 thousand) – The costs were incurred primarily for training Planners. In 2010, there were five new hires in the Install Coordinator (Planner) groups to go with an extensive new hire in 2009. These groups are responsible for new customer attachments and planning of system integrity and reliability projects. The new hires were the result of turnover in the group as well as retirements. The planning groups have some of the most complex and extensive training requirements in the Company and this placed unusual pressure on the group in order to ensure the newer employees were sufficiently trained to meet customer's expectations and service levels.

- Vegetation Management / Right of Way Clearing ($168 thousand) – Additional outstanding work was released to the contractor as the clearing season was extended due to favourable weather conditions late in the year in the eastern portion of the province.

- First Response Standby Reduction ($700 thousand savings) - Offsetting the principal 2010 cost pressures above was a reduction in first response standby. First response standby costs are generated when field resources are on standby and have no other work available to them, much like the fire department model. Typically, standby costs are more unavoidable in small towns where there is a requirement to have a service technician in town for emergency response and routine customer service calls; however, if the service technician does not have a full schedule of maintenance or capital work, standby costs are incurred. Having capital work (from the asset management and planning groups), customer service work, emergency work and routine operations and maintenance work activities available to crews and technicians in a timely manner in the right locations allows for the optimization of the resources and results in reductions to standby costs. The reductions to first response standby have been primarily due to being able to assign resource capacity to customer additions and capital hazard mitigation activities. Favourable weather, particularly in the Interior during the winter, also contributes to the reduction in standby as crews and technicians are able to complete more work without weather related restrictions.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution O&M of $43.2 million is expected to equal the allowed amount of $43.2 million under the 2010-2011 RRA as several of the items identified as contributing to the Distribution overage in 2010 were considered unusual expenditures unlikely to repeat in 2011.

5.3.5.4 Distribution 2010 and 2011 Review - Vancouver Island

2010 ACTUAL VERSUS 2010 ALLOWED

Distribution met its program commitments in 2010 to Vancouver Island customers as outlined in the 2010-2011 RRA, and, in doing so, was $0.4 million or 7 percent under-budget. The principal reason the 2010 actual varied from the 2010 allowed is:

- First Response Standby Reduction ($465 thousand savings) – As discussed in the Mainland section above, first response standby costs are generated when field resources are on standby and have no other work available to them, much like the fire department model. Reductions in first response standby on Vancouver Island were primarily due to available O&M and capital work (new customer additions activities) in areas where there was internal resource capacity and less need to use a contractor.

- The 2010 savings were partially offset by increased leak survey costs ($88 thousand). Leak survey is an activity that can be used to reduce the impacts of first response standby time; however, the FEVI field resources performing leak survey are typically higher cost than the leak survey contractor due to higher wages and benefits. FEVI technicians are required to be available to respond to emergencies such as hit lines, gas odour and fire calls, and the leak survey work is operations work that can easily be postponed temporarily and resumed after the emergency event is resolved.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution O&M of $5.4 million is expected to equal the Allowed amount under the 2010-2011 RRA (reduced by $350 thousand from 2010) which represents the permanent portion of the savings in first response standby costs achieved in 2010.

5.3.5.5 Distribution 2010 and 2011 Review - Whistler

2010 ACTUAL VERSUS 2010 ALLOWED

Distribution met its program commitments to Whistler customers as outlined in the 2010-2011 RRA, and, in doing so, was $63 thousand or 14 percent under-budget. The principal reasons the 2010 actual varied from the allowed were:

- Industrial Meter Set Preventive Maintenance ($20 thousand savings) – these meter sets were put in place in 2009 during the Whistler Conversion project (propane to natural gas) and little scheduled maintenance was required in their first year of operation.

- Distribution Manager Position ($20 thousand savings) – Subsequent to the Whistler Conversion project being completed, an appropriate system stabilization period and the 2010 Olympics, the Distribution Manager position located in Whistler was eliminated. The propane to natural gas conversion eliminated many of the activities and complexities of a satellite propane system, making the service territory manageable from Burnaby. Half of the manager's salary was included in the Whistler 2010 O&M budget and the change was made July 2010, resulting in a savings for half of the year. The Burnaby manager allocates 10 percent of his salary to Whistler under the new arrangement.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution O&M of $451 thousand is expected to equal the Allowed amount under the 2010-2011 RRA. The reduction in Distribution Manager costs is permanent; however, in 2011 these savings are expected to be offset by continued system stabilization repair work (gas odour calls, leak repairs, meter set maintenance). These activities have increased as Whistler conversion customers were encouraged to call in upon the detection of any gas odour to ensure the many fittings touched during the conversion were tightened and that the conversion had been completed safely and to the customers' satisfaction.

5.3.5.6 Distribution 2010 and 2011 Review - Fort Nelson

2010 ACTUAL VERSUS 2010 ALLOWED

The principal reasons the 2010 actuals varied from the allowed amount were due to reductions in vehicle and employee related expenses.

2011 PROJECTION VERSUS 2011 ALLOWED

The 2011 Projected Distribution Fort Nelson O&M of $347 thousand is expected to equal the allowed amount as part of the 2011 Fort Nelson RRA.

5.3.5.7 Distribution 2012 and 2013 Forecast – Mainland

The Mainland requires incremental O&M in 2012 and 2013 to ensure we continue to provide safe, reliable, cost-effective service to our customers. The requirements are presented under the following three cost driver categories and are summarized in Table 5.3-17 below:

1. Codes and Regulations;
2. Demographics; and
3. Service Standards and Reliability.

Table 5.3-17: Increases Required to Meet Mainland Regulatory Requirements and Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	43,153	(54)	1,738	120	-	160	2,520	4,485	47,638
2013	47,638	-	1,307	600	-	270	1,243	3,420	51,058

The Mainland requests include incremental positions for Asset Management and the Distribution Centralized Support Services (Process Support and the Operations Centre). Further details and explanations are presented below.

CODES AND REGULATIONS

Incremental O&M is required to comply with codes and regulations. The Mainland's goal of providing safe, reliable, cost effective and environmentally responsible service is strongly aligned to code requirements. In 2012, $120 thousand is required for pipeline right-of-way signage which is related to a colour change in the standard from orange to yellow for natural gas markers. In 2013, $250 thousand is required for additional Asset Compliance Managers and $350 thousand is required for the standardization of locks and security devices at field facilities. Further details are provided below.

Pipeline right-of-way signage is required to meet CSA Z662 code and to identify the presence of pipelines in order to reduce the possibility of damage and interference. ANSI standard Z535.1 requires natural gas markers to be yellow, instead of orange. FEU has implemented this change for distribution pressure mains and it is necessary to extend this program to pipelines in order to achieve compliance.

Asset compliance management is a requirement under the Integrity Management Plan which has evolved to meet CSA Z662 code and safety and reliability objectives. Two Asset Compliance Managers were approved in the 2010-2011 RRA and subsequently hired in 2011 to develop processes and conduct quality audits to ensure field work meets code and internal standards. Three additional Asset Compliance Managers are requested in order to provide one manager per operational zone and facilitate effective monitoring of field work activities, particularly in light of the number of new employees, employees new in positions and contractors performing significant portions of new main and service installations. It is neither feasible nor practical to have two Asset Compliance Managers cover the entire five gas distribution service areas and the full scope of activities including new installations, routine operations and maintenance, emergencies, customer service work, design, and planning.

FEU must standardize locks and security devices at field facilities to meet code requirements and maintain adequate security measures (CSA Z662 and CSA Z246.1) to ensure only authorized personnel have the appropriate access to facilities and operating equipment. This is particularly important as the amalgamation of different companies and operating areas (the last one being Vancouver Island in 2006) has resulted in different keys and locks being used in different areas across the Province, limiting the ability to effectively move personnel and provide access to facilities as the work requires. FEU will implement a lock standardization program. The program plans to complete 50 percent of the lock upgrade and replacements in 2013 and complete the remainder of the program in 2014.

These additional costs are necessary to meet specific code and regulation requirements.

DEMOGRAPHICS

The Distribution group requires incremental O&M of $160 thousand in 2012 and $270 thousand in 2013 to address demographic challenges. Even with the relatively high number of retirements over the past five years, Distribution still has 90 employees eligible to retire. Distribution hired 53 new field employees in 2010 to fill a large number of vacancies created primarily by retirements (33). Distribution anticipates further retirements by the end of 2013 and is planning to hire new employees in 2012.

Distribution continues to be proactive by planning for inevitable replacements and ensuring new staff has progressed to ensure that a capable and competent workforce is maintained. Distribution has adopted a peer training model for the majority of field training which involves employees who currently work in the field also delivering training programs. An additional resource is required to manage and administer the peer training to ensure field resources are trained and skilled to meet regulatory and operating requirements. This new role will be required to work in conjunction with the Training group to coordinate the IBEW training (400+ field personnel) plus all the peer trainers (25+ field personnel) which are used by the Training group to provide the instruction. The Mainland requests approval of $90 thousand in 2012 to support this role, plus an additional $200 thousand in 2013 for the required training and development of field personnel.

In addition, Distribution has an aging management workforce resulting in significant attrition risk over the next five years. This risk has increased since the 2010-2011 RRA filing. More than 40 percent of current management employees become eligible to retire, with either a reduced or unreduced pension next year. Distribution will require $70 thousand in 2012 and a further $70 thousand in 2013 to develop new managers through the Manager-In-Training program and to ensure knowledge transfer and planning for replacement of management employees over the next few years.

SERVICE STANDARDS AND RELIABILITY

In order to continue to provide safe and reliable services, additional resources and investment are required to support the Operations Centre, Asset Management, field service delivery, IT system applications and system sustainment assessments. Further details are provided below.

OPERATIONS CENTRE

The Operations Centre, which is the Distribution centralized office group located primarily in Surrey and responsible for initiating, planning, scheduling, dispatching and closing the Capital and O&M field activities for the whole service territory, is facing an increasing workload from customer growth, customer expectations, process changes (enhancements to the estimating process) and changes in capital programs and requires additional resources in order to manage the workload. The increases in capital workload are primarily related to the hazard mitigation program, meterset upgrades, inactive meters and services programs and third party relocations such as the Gateway projects in the Lower Mainland. FEI requires $448 thousand of O&M in 2012 and $58 thousand of O&M in 2013 to hire the additional resources to manage the workload and maintain service standards in the Operations Centre group.

The Operations Centre will require six additional positions in 2012 and three additional positions in 2013 to address the increase in workload. In 2012, three Planners and three Operational Support Representatives ("OSRs") in the Closing and System Survey sub-group of the Distribution group are required. In 2013, three additional Planners, including a work-leader to supervise a large planning group, are required. The Planners, who typically meet on construction sites with homeowners, developers and municipalities to design and cost estimate gas system infrastructure, are required primarily for capital activities; however, they also engage in training, supervision and reviews of municipal project plans which are classified as O&M activities.

ASSET MANAGEMENT

The Asset Management group requires an analyst and assistant in 2012 ($160 thousand). Two assistants are required in 2013 ($140 thousand). These roles will support O&M, capital, sustainment planning and the NGV and biomethane programs. The existing and new assets require maintenance planning and administration to ensure ongoing safety, reliability and cost effectiveness. Asset Management must be adequately staffed with skilled personnel in order to manage the increased workload (new NGV and biomethane assets, internal reporting and data management to improve asset management) and meet customer and regulatory requirements. Asset Management requires adequate skilled resources to ensure capital investments are properly screened, prioritized and administered.

Distribution also requires a reporting analyst ($90 thousand) to manage steadily growing internal and external operational reporting requirements as well as reporting technology changes and individual and departmental performance management. Distribution also requires a process support analyst ($70 thousand) to manage the increase in system applications supported and number of users.

FIELD SERVICE DELIVERY

Field Service Delivery includes six primary work categories: Preventive Maintenance, Corrective Maintenance, Operations, Meter Exchange, Emergency Management and Meter to Cash. The Field Service Delivery budget is the largest component of the Distribution budget at $20.8 million. Incremental increases in O&M of $416 thousand in 2012 and $272 thousand in 2013 are required in the category of Service Standards and Reliability for field service delivery activities. The changes in budget requirements are caused by changes in activity levels and unit costs. Activity levels are impacted by system and customer growth and maintenance frequencies. Unit costs are impacted by labour/vehicle rates as well as the efficiency and experience of the employees and contractors performing the activities. 2012 and 2013 forecast unit costs primarily reflect the 2010 experience together with inflation.

A new area within the Preventive Maintenance category is the budget to operate and maintain NGV and biomethane assets.

Regular operation and maintenance of NGV assets, specifically CNG and/or LNG stations, are required to ensure public safety and reliability. Starting in 2012, the O&M costs will be forecast in Distribution, and as the number of NGV assets increases, the operation and maintenance requirements will increase. The Mainland requires $225 thousand in 2012 and an incremental $115 thousand in 2013 to operate and maintain the NGV assets. A summary of all NGV costs and revenues is included in Appendix I.

Biomethane service received a two-year Commission approval for inclusion in the regulated natural gas utility business. Regular operation and maintenance of biomethane assets, similar to pressure regulating stations, is required. Starting in 2012, the O&M costs will be forecast in Distribution, and as the number of biomethane assets increase, the operation and maintenance requirements will increase. The Mainland requires $23 thousand in 2012 and an incremental $68 thousand in 2013 to operate and maintain the biomethane assets. A summary of all biomethane costs and revenues is included in Appendix J.

Also included in the Field Service Delivery category, driven by changes in activity levels and inflation in unit costs or a combination thereof, are additional funds for:

- Battery upgrades for industrial meters ($160 thousand);
- Bridge crossing repairs ($110 thousand);
- Station transition repairs ($100 thousand);
- Leak repairs ($110 thousand);
- Line locates ($125 thousand);
- Valve inspections ($200 thousand);
- Gas odour calls ($200 thousand); and
- Meter to cash (lock-offs, etc.) ($1.13 million).

These additional requests are partially offset by the following savings:

- Operations – general (primarily line heater fuel) ($590 thousand);
- First response standby ($440 thousand); and
- Meter to cash recoveries ($1.12 million). The Companies plan to increase the reconnection/reactivation fee to $100 (regular hours) and $140 (after hours) as allowed

under their General Terms and Conditions. The proposed change reasonably reflects the cost of providing this service and is consistent with cost causation principles. The proposed fee change also mitigates negative impacts to other ratepayers and reduces the O&M cost per customer for all customers. For details on the planned fee increase, please refer to Appendix F-1.

IT SYSTEM APPLICATIONS

The Mobile Geographic Information System ("GIS") initiative was implemented in 2011 to provide field crews and technicians with remote access to service and main records. This initiative is demonstrating many benefits, particularly for emergency field personnel who now have visibility into up-to-date gas plant records information from their vehicles. An additional $200 thousand in 2012 is required to support the ongoing licensing costs and add a resource to provide technical system support.

SYSTEM SUSTAINMENT ASSESSMENTS

The requirement for a long term view of system sustainment was presented earlier in this section as part of Asset Management. This supports our prudent operational priorities by enabling a long term view of system sustainment to minimize the likelihood of unexpected asset failures in the future and reducing future cost and rate volatility due to reactive asset management. This also provides the assurance to stakeholders that related capital investments have been reviewed and planned in the best interest of both customers and the general public.

The O&M to support this initiative is forecast to be $1 million in 2012 and $500 thousand in 2013. Partially offsetting these increases are O&M reductions resulting from the elimination of similar studies that were completed in 2011 (seismic risk analysis for $145 thousand and single point of failure analysis for $200 thousand). Therefore, the net increase as compared to 2011 is $655 thousand in 2012 and $500 thousand in 2013.

In order to support the distribution system sustainment assessments, Asset Management will require the following additional resources: one engineer and two analysts in 2012 ($150 thousand), and one additional analyst in 2013 ($45 thousand). These resources are in addition to those identified to support Regular Operations and are required to ensure Asset Management has adequate skilled resources to ensure capital investments are appropriate, prioritized and administered effectively. In addition in 2012, the Operations Centre will require additional planners ($100 thousand) to manage increases in workload associated with the system sustainment assessments. The planners will work with engineers and analysts to plan, design and estimate changes such as new installations, alterations and abandonments to the gas distribution system. The Operations Centre requires adequate skilled resources to continue to plan, design and coordinate asset renewal projects and ensure capital investments are appropriately coordinated.

VEHICLE AND OTHER NON-LABOUR INFLATION

Also included in the Service Standards and Reliability category is $256 thousand in 2012 and $228 thousand in 2013 for vehicle and other non-labour inflation such as contracts and materials.

5.3.5.8 Distribution 2012 and 2013 Forecast - Vancouver Island

Vancouver Island requires incremental O&M in 2012 and 2013 to ensure we continue to provide safe, reliable, cost-effective service to our customers. The incremental O&M is shown in Table 5.3-18 below, broken down by cost driver.

Table 5.3-18: Increases Required to Meet Vancouver Island Regulatory Requirements and Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	5,379	(31)	87	-	-	-	353	409	5,787
2013	5,787	-	139	40	-	-	402	582	6,369

CODES AND REGULATIONS

The incremental O&M in this category is Vancouver Island's allocation of costs to complete the lock standardization program planned starting in 2013. This program is described above in the Mainland section.

SERVICE STANDARDS AND RELIABILITY

Additional investment of $353 thousand is required in 2012 to support various field service delivery activities which are defined in the Mainland section above. In addition to minor changes in field service delivery activities in 2013, the significant item for 2013 is bridge crossing repairs for the Bay Street bridge in Victoria which is estimated at $330 thousand. The work includes repairing and recoating the two pipes (distribution pressure and intermediate pressure) which are supported by the bridge.

5.3.5.9 Distribution 2012 and 2013 Forecast - Whistler

The Whistler O&M requirement for 2012-2013 is shown in Table 5.3-19 below, broken down by cost driver.

Table 5.3-19: Efficiencies Realized in Meeting Whistler Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	451	-	21	-	-	-	(42)	(21)	430
2013	430	-	6	-	-	-	(6)	(0)	430

SERVICE STANDARDS AND RELIABILITY

The costs for Whistler are forecast to decrease in the 2012-2013 period from 2011 due primarily to the reduction in management costs and declining system post-conversion repairs. Partially offsetting these reductions are annual inflation and scheduled commercial/industrial meter maintenance ($20 thousand) coming due in 2012 that is on a three year cycle.

5.3.5.10 Distribution 2012 and 2013 Forecast - Fort Nelson

Fort Nelson requires similar O&M levels in 2012 and 2013 as compared to 2011 to ensure we continue to provide safe, reliable, cost-effective service to our customers. Some minor inflationary wage pressures are offset by some minor expense and material savings which together are embedded in the Service Standards and Reliability category. The Fort Nelson operation consists of three employees and the annual expenditure requirement is a mix of direct costs and allocated costs from FEI.

Table 5.3-20: Changes in O&M to Meet Fort Nelson Service Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	347	-	-	-	-	-	(4)	(4)	344
2013	344	-	-	-	-	-	7	7	350

5.3.5.11 Transmission O&M Expenditures and Employees

Code and regulations compliance forms the foundation of many of our operating programs and activities in the Transmission area. Code changes, asset age, asset base expansion, and inflation all drive the need for incremental O&M funding in the Transmission group to allow FEU to continue to provide natural gas service in a safe and reliable manner. Table 5.3-21 sets out approved, actual, projected, and forecast O&M costs for Transmission. These costs are reviewed later in this section.

Table 5.3-21: Transmission O&M Requirements to Meet Future Obligations

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 14,116	$ 13,871	$ 14,994	$ 14,994	$ 16,280	$ 17,499
Vancouver Island	$ 4,849	$ 4,542	$ 6,134	$ 6,134	$ 6,755	$ 7,064
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 18,965	$ 18,413	$ 21,128	$ 21,128	$ 23,036	$ 24,562

The cost of employees needed for the completion of Transmission work activities are included in the O&M costs that are set out in Table 5.3-21 above. Employees consist primarily of M&E, COPE, and IBEW resources required to manage, initiate, plan, schedule, dispatch, and complete field work. Table 5.3-22 below sets out approved, actual, projected, and forecast employees for Transmission.

Table 5.3-22: Transmission Employees Required to Meet Future Obligations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	54	53	54	55	59	60
Vancouver Island	21	28	31	31	33	34
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	75	81	85	86	92	94

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	0	0	5	5	6	6
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	0	0	5	5	6	6

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	54	53	49	50	53	54
Vancouver Island	21	28	31	31	33	34
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	75	81	80	81	86	88

Two key requirements explain the increased need for employees by Transmission since 2010. First, the completion of the Mt. Hayes LNG facility in 2011 on Vancouver Island required 10 new operators to complete daily operating activities. Second, an additional four employees are required in 2012, followed by an addition of two more employees in 2013. The four employees in 2012 are comprised of management and field staff for the increased asset management activities that the Companies expects as it completes detailed assessments of aging assets to determine the scope and timing of future asset renewals. The role and importance of these asset management activities was discussed in Section 5.3.5.1. Of the two additional employees required in 2013, one will replace a contractor that is retiring in 2013 who operates the Company's V4 compressor, and the second is a pipeline technician required for the operation of the Vancouver Island transmission system.

In addition to the employees set out in the table above, the Companies engage contractors and consultants for completion of Transmission O&M work activities. These resources are required to supplement employees in areas where in-house expertise is unavailable, where the resource is a temporary requirement, or where it is economical to outsource. The most significant categories of contractor usage include pipeline line patrols, leak survey, and vegetation clearing.

An overview of the O&M changes for Transmission included in this Application is provided in Sections 5.3.5.12 through 5.3.5.15 below.

5.3.5.12 Transmission 2010 and 2011 Review – Mainland

2010 ACTUAL VERSUS 2010 ALLOWED

2010 actual Transmission O&M costs on the Mainland were $245 thousand lower than allowed in 2010. This variance is comprised of a number of changes from what was anticipated in preparing the 2010 forecasts. Key cost savings include:

- $147 thousand - warmer than normal weather resulted in lower electricity use;
- $123 thousand - lower than planned own use gas costs;
- $215 thousand - Transmission Pipeline Integrity Program ("TPIP") contractor bids more competitive than planned; and
- $282 thousand – several M&E and COPE positions remained unfilled until later than planned in the year.

Offsetting the above cost savings was the following key cost pressure:

- $522 thousand – higher than planned Transmission right of way activities, including unplanned land easement, fencing compensation, and city and owner court settlement costs.

All of these variances are expected to be one-time and are non-recurring in nature.

2011 PROJECTION VERSUS 2011 ALLOWED

No variance from the 2011 approved forecast is projected at the time of this Application.

5.3.5.13 Transmission 2010 and 2011 Review - Vancouver Island

2010 ACTUAL VERSUS 2010 ALLOWED

Actual Transmission O&M costs on Vancouver Island were $307 thousand lower than allowed in 2010. This variance is comprised of a number of changes from what was anticipated in the 2010 forecast. Key cost savings include:

- $154 thousand – ability to reduce the need to complete planned seismic activities;
- $81 thousand – ability to reduce the need to complete planned compressor station maintenance and carbon studies; and
- $110 thousand – higher than planned charge out to complete capital activities.

Offsetting the above cost savings was the following key cost pressure:

- $38 thousand – Mt. Hayes LNG operators hired earlier than planned.

All of these variances are expected to be one-time and are non-recurring in nature.

2011 PROJECTION VERSUS 2011 ALLOWED

No variance from the 2011 approved forecast is projected at the time of this Application.

5.3.5.14 Transmission 2012 and 2013 Forecast - Mainland

Transmission requires approximately $1.3 million in incremental O&M costs for 2012 and a further $1.2 million in incremental O&M costs for 2013 for Mainland operating and maintenance activities. A discussion of these cost increases by cost driver follows.

Table 5.3-23: Incremental Transmission O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	14,994	(57)	244	(130)	133	91	1,005	1,287	16,280
2013	16,280	-	185	(75)	106	(46)	1,048	1,218	17,499

CODES AND REGULATIONS

Underpinning the safety and reliability of the transmission system is the need to ensure compliance with a range of key codes and regulations. Legislation such as the UCA, *Oil and*

Gas Commission Act, *Workers' Compensation Act*, *Environmental Management Act*, *Safety Standards Act*, fire codes and safety standards, Provincial and Federal Emergency Acts, Canadian Standards Association ("CSA") codes, and other legislation, regulations and bylaws define compliance activities.

Transmission is forecasting a decrease in O&M to as it relates to the need to comply with codes and regulations in 2012. A number of activities needed and completed in 2011 are non-recurring and no longer required. These activities were all driven by the need to comply with Annex A of CSA Z662 and involved work to set up a safety and loss management system applicable to design, construction, operation, and maintenance activities that can affect the safety of people or the protection of property or the environment. The work to set up this safety and loss management system is now complete, which results in the ability to reduce O&M by $250 thousand in 2012. This savings is offset by a $120 thousand cost increase driven by the need to ensure that transmission pipeline signage meets CSA Z662 code to clearly identify the presence of pipelines in order to reduce the possibility of damage and interference.

In 2013, vegetation control costs are expected to decrease by $150 thousand because of competitive bids for vegetation control work which are lower than in previous years. This savings is offset by a cost increase of $75 thousand that is necessary for the recertification of pressure safety valves used in Transmission's compressors. This recertification requirement reoccurs on a three year cycle.

CUSTOMER AND STAKEHOLDER EXPECTATIONS

Increased O&M costs will be incurred to support the Companies' NGV program which is expected to start in 2011 subject to Commission approval of FEI's NGV Application. Increased liquefaction will be required to provide this service throughout 2012 and 2013 in order to replenish LNG tank levels. The additional O&M cost in 2012 is expected to be $133 thousand and followed by an additional $106 thousand in 2013 as the service ramps up. These incremental costs are expected to be offset in the revenue requirement by incremental revenue that should be earned from providing this service under Rate Schedule 16. A summary of all NGV costs and revenues is included in Appendix I.

DEMOGRAPHICS

Transmission requires three transitional field employees in order to manage a number of field workforce retirements that are expected in 2012 and 2013. The additional cost to manage these retirements is estimated to be $91 thousand in 2012 followed by a decrease of $46 thousand in 2013. Given the difficulty in recruiting and training these replacement employees, Transmission has assumed that each is required for a six month transition period, two in 2012 and an additional one in 2013. After this transition period ends, these costs will be offset by the three employees who are expected to retire. The initial savings in labour costs from the two employees anticipated to retire by the end of 2012 is reflected in the decrease that is expected for 2013.

SERVICE STANDARDS AND RELIABILITY

Transmission needs an additional $693 thousand in incremental O&M in 2012 and an additional $201 thousand in 2013 on Vancouver Island to meet its objectives related to Service Standards and Reliability. These amounts are comprised of standard inflation on materials for a total of $65 thousand in 2012 and an additional $66 thousand in 2013, and the need for additional Transmission pipeline employees for a total of $170 thousand in 2012 and an additional $95 thousand in 2013. An additional $166 thousand is required in 2012 for Mt. Hayes LNG plant operators who were able to capitalize a portion of their labour costs in 2011 while assisting with the construction of the LNG facility. The access road leading to the new Mt. Hayes LNG facility requires an additional $50 thousand in 2012 for ongoing annual maintenance. Additionally, Mt. Hayes will incur incremental electricity costs required for ongoing liquefaction and vaporization activities. In 2012 Mt. Hayes is forecast to incur additional electricity costs, net of a minor fuel gas savings, totalling $242 thousand. In 2013 electricity costs are expected to increase a further $40 thousand.

5.3.5.15 Transmission 2012 and 2013 Forecast - Vancouver Island

Transmission requires $621 thousand in incremental O&M funding in 2012 and a further $308 thousand in 2013 for Vancouver Island Transmission system operating and maintenance activities. A discussion of these increases by cost driver follows.

Table 5.3-24: Incremental Transmission O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	6,134	(41)	62	(92)	-	-	693	621	6,755
2013	6,755	-	63	45	-	-	201	308	7,064

CODES AND REGULATIONS

A number of non-recurring activities in 2011 that resulted from CSA Z662 are no longer required. In particular, aerial recoating, inline inspection activities, and seismic inspection activities required by CSA Z662 are complete for the 2012 and 2013 period, which results in an O&M reduction of $187 thousand in 2012. This savings is offset in 2012 by primarily two items: (1) a $20 thousand cost increase driven by the need to ensure that transmission pipeline signage meets CSA Z662 code to clearly identify the presence of pipelines in order to reduce the possibility of damage and interference and (2) an additional $75 thousand to manage the existing condition of vegetation growing on transmission rights of way on the Vancouver Island system.

In 2013, a cost increase of $45 thousand is forecast for the recertification of pressure safety valves used in Transmission's compressors. This recertification requirement reoccurs on a three year cycle.

SERVICE STANDARDS AND RELIABILITY

Transmission needs an additional $693 thousand in incremental O&M in 2012 and an additional $201 thousand in 2013 on Vancouver Island to meet its objectives related to Service Standards and Reliability. These amounts are comprised of standard inflation on materials for a total of $65 thousand in 2012 and an additional $66 thousand in 2013, and the need for additional Transmission pipeline employees for a total of $170 thousand in 2012 and an additional $170 thousand in 2013. An additional $166 thousand is required in 2012 for Mt. Hayes LNG plant operators who were able to capitalize a portion of their labour costs in 2011 while assisting with the construction of the LNG facility. The access road leading to the new Mt. Hayes LNG facility requires an additional $50 thousand in 2012 for ongoing annual maintenance.

5.3.5.16 Operations Summary

Outside of inflationary pressures, the main contributors to the increase in 2012 and 2013 forecast O&M expenditures for the Operations department relate to demographics, service standards and reliability, and code and regulations compliance.

Having effective asset, distribution and transmission system management is necessary to help ensure reliable, secure, and cost effective supplies of natural gas and propane to customers. The Operations department believes the costs it has presented are prudent and necessary to meet the above objectives and customer priorities.

5.3.6 ENERGY SUPPLY AND RESOURCE DEVELOPMENT

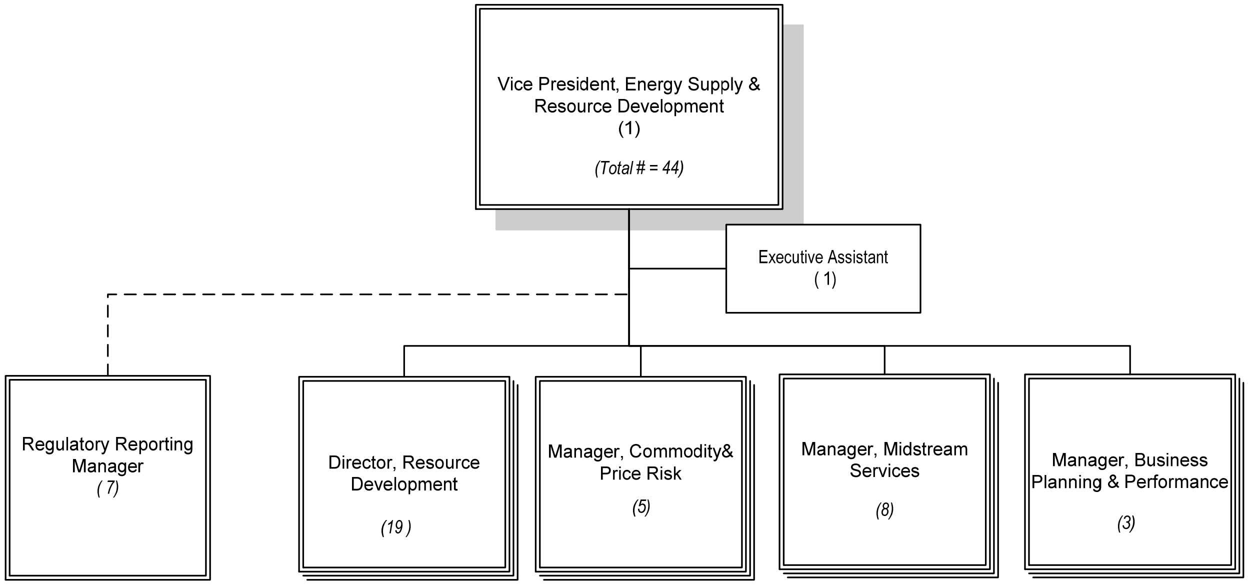
5.3.6.1 Departmental Overview

The Energy Supply and Resource Development department is responsible for two broad functional areas of activity – Energy Supply, and Resource Development. The purpose of each of these two functional areas and the scope of their activities are described in the following section.

ENERGY SUPPLY AND RESOURCE DEVELOPMENT ORGANIZATIONAL STRUCTURE

The organizational chart for the Energy Supply and Resource Development department is presented below.

Figure 5.3-2: Organization Chart for Energy Supply and Resource Development



ENERGY SUPPLY

The main activities for Energy Supply include completing gas commodity procurement, providing intra-day balancing supply (required primarily due to weather changes) for core customers, facilitating all gas scheduling and nominations on FEU and third party pipeline transmission systems, mitigation activity based on buying and selling around excess resources and the management of relationships with financial and physical supply counterparties, storage operators and pipeline companies to the benefit of customers. Also included is the management of the movement of gas supply provided by natural gas marketers to customers under the commodity unbundling program, which began in 2004.

The completion of these activities helps to ensure that there are reliable and secure supplies of natural gas and propane for all of the Company's customers. The key objectives of the Energy Supply department include:

- providing natural gas and propane supply for customers;
- optimizing resources to minimize the overall supply portfolio costs for the benefit of customers;
- managing market price risk to reduce rate volatility for customers;
- providing Energy Management Services to create value for customers through revenue generation; and
- managing commercial and industrial transport customers' requirements.

RESOURCE DEVELOPMENT

The Resource Development group provides the gas supply infrastructure planning and major capacity and sustainment initiatives management function. The group is responsible for identifying and developing new regional projects as well as system infrastructure projects within the Company's current service areas, including pipeline, compressor, and storage projects. Identifying the need for such major initiatives and projects is important in order to determine and plan infrastructure projects required for system reliability and to meet demand growth. Once these projects have been built and the assets commissioned they become the responsibility of the Asset Management group in Operations for ongoing management.

Long range planning for the Companies' gas system infrastructure is necessary given the long lead times for large infrastructure projects that typically face a range of extensive regulatory approvals, public consultation, conceptual design, detailed engineering, and construction schedules. This work forms a critical link in the Company's ability to provide safe, reliable, and cost effective service to customers. The Company will continue to place a high priority on the completion of these activities.

The organizational structure displayed in Figure 5.3-2 includes the Gas Control group reporting to Resource Development. The primary function of Gas Control is to dispatch and operate the gas transmission and distribution system, in a manner to meet the corporate obligation of safe, dependable and economical gas service to its customers. Gas Control is a 24/7 operation, and is responsible for the continuous monitoring and operation of the pipeline to meet its customers energy, pressure and gas quality requirements with maximum dependability. In addition, Gas Control performs the daily system load forecasts, as well as short-term 5-day forecasts for gas commodity purchasing

5.3.6.2 Energy Supply & Resource Development O&M Expenditures Overview and Employees

Energy Supply and Resource Development groups are funded from two sources - a CMAE budget and an O&M budget. CMAE costs are a direct result of the activities performed within the Energy Supply department to serve core market customers and are treated as a flow-through cost to core market customers as part of gas costs. These costs are not included in O&M in this RRA as the costs form part of commodity rates and not delivery rates. CMAE costs are reviewed in detail in the cost of gas Section 5.2 of this Application.

All other activities, including those completed by the Resource Development department, are required in support of all customers, not just for core customers, and are as a result funded from the O&M budget. Table 5.3-25 sets out approved, actual, projected, and forecast O&M costs for Energy Supply and Resource Development. These costs are reviewed later in this section.

Table 5.3-25: Energy Supply & Resource Development O&M Requirements to Meet Future Obligations

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 3,325	$ 3,251	$ 3,748	$ 3,748	$ 3,943	$ 4,196
Vancouver Island	$ -	$ -	$ 100	$ 100	$ 100	$ 100
Whistler			$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 3,325	$ 3,251	$ 3,848	$ 3,848	$ 4,043	$ 4,296

The cost of employees needed for the completion of Energy Supply and Resource Development work activities are included in the O&M costs that are set out in Table 5.3-25 above. Employees consist primarily of M&E and COPE resources required to manage, initiate, plan, schedule, and complete work activities. Table 5.3-26 that follows sets out approved, actual, projected, and forecast employees for Energy Supply and Resource Development.

Table 5.3-26: Energy Supply & Resource Development Employees Required to Meet Future Obligations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	42	40	42	45	46	47
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	42	40	42	45	46	47
Less: CMAE	(21)	(20)	(21)	(22)	(22)	(22)
Net O&M	21	20	21	23	24	25

Energy Supply and Resource Development is forecasting the addition of four employees after 2010. Two new employees were added in 2011 as business development specialists to help the Resource Development group with work identifying and developing new regional projects as well as system infrastructure projects. An additional two employees are expected to be required after 2011 for this group, one in 2012 and the second one in 2013. Both employees will also work as business development specialists that are required to assist the Resource Development group to meet its objectives.

In addition to the employees set out in the table above, the Company engages contractors and consultants for completion of Energy Supply and Resource Development O&M work activities.

These resources are required to supplement employees in areas where in-house expertise is unavailable, where the resource is a temporary requirement, or where it is economical to outsource.

Sections 5.3.6.3 through 5.3.6.5 below provide review of O&M expenses for Mainland and Vancouver Island.

5.3.6.3 Energy Supply & Resource Development 2010 and 2011 Review - Mainland

Energy Supply and Resource Development incurred O&M expenditures prudently in 2010 and 2011 to operate the Company's energy supply and gas control functions and to meet resource development objectives. Energy Supply and Resource Development met its program commitments, with O&M $75 thousand (2.2 percent) lower than approved in 2010.

No variance from the 2011 planned budget is projected at the time of this Application.

5.3.6.4 Energy Supply & Resource Development 2012 and 2013 Forecast - Mainland

Changes to the level of O&M costs from those approved for 2011 are identified in the table below, broken out by cost driver. These changes reflect both cost savings and cost increases, to ensure savings opportunities were reflected in the overall O&M impact.

Energy Supply and Resource Development requires approximately $195 thousand in incremental O&M cost for 2012 and a further $253 thousand in incremental O&M costs for 2013 that are required for Mainland Energy Supply and Resource Development activities. A discussion of these cost increases by cost driver follows.

Table 5.3-27: Mainland ES&RD O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	3,748	(14)	125	-	-	-	84	195	3,943
2013	3,943	-	99	-	-	-	154	253	4,196

SERVICE STANDARDS AND RELIABILITY

Energy Supply and Resource Development requires an additional $84 thousand in O&M funding in 2012 and an additional $154 thousand in 2013. As described earlier in the discussion on the level of employees required by this business area, Resource Development has identified the need to add one employee in 2012 and an additional employee in 2013. The costs included assume that each employee will be hired mid-year.

5.3.6.5 Energy Supply & Resource Development 2012 and 2013 Forecast - Vancouver Island

Energy Supply and Resource Development has not identified any incremental O&M funding needed in 2012 or in 2013 for Vancouver Island Energy Supply and Resource Development activities.

Table 5.3-28: Vancouver Island ES&RD O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	100	-	-	-	-	-	-	-	100
2013	100	-	-	-	-	-	-	-	100

5.3.6.6 Energy Supply & Resource Development Summary

In summary, outside of inflationary pressures, the main contributor to the increase in 2012 and 2013 forecast O&M expenditures for ES&RD relates to improving service standards and reliability.

5.3.7 CUSTOMER SERVICE

5.3.7.1 Departmental Overview

The Customer Service Department of FEU plays a vital role in providing service to customers, and consequently represents a core element of the business. It is the central point of interaction between customers and FEU in key aspects of its operations, and significant emphasis is placed in ensuring that service delivery meets customer needs.

The Customer Service department is responsible for providing accurate and timely billing for our customers, for ensuring that meters are read regularly and accurately, for providing effective and timely resolution of customer inquiries, and for providing customers with valuable energy consumption information. The majority of these activities are currently managed by the Customer Service department by way of a Business Process Outsourced[80] ("BPO") arrangement with CustomerWorks LP ("CWLP")[81]. The department also oversees mass market customer communications regarding accounts and billing, administers the Customer Choice program, performs market research and analysis, oversees mass market bad debt management, works to swiftly resolve customer issues raised to third parties including the BCUC, Better Business Bureau and Provincial MLAs, and provides contact centre services for

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80 Business Process Outsourced Agreement is the contracting of a specific business task, including all responsibility for management of the business processes and underlying information technology system and applications.

81 The scope and terms of the BPO arrangement with CWLP was defined as a Client Services Agreement dated January 1, 2002.

customer construction requests including new service line installations, service alterations and abandonments through its Construction Services Contact Centre.

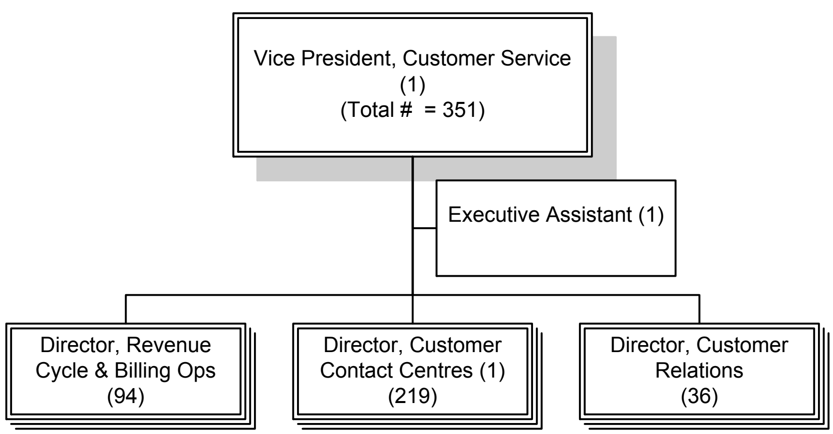
Prior to the second quarter of 2010, the Customer Service group was a division of the Energy Solutions and External Relations department (formerly known as the Marketing and Business Development department), and has since formed a separate department. This separation was in preparation for the in-sourcing of key customer service activities provided by the BPO Arrangement. The CCE Project[82] is well underway and the project team is preparing the Companies for the in-sourcing transition by way of implementing technologies, including a new Customer Information System technology platform integrated with new contact centre technologies for managing customer interactions; along with the development of new business processes to support the capability to deliver customer service excellence.

In 2012, the CCE Project will be complete and the Customer Service department will transition to a strategic sourced[83] framework with direct control over customer points of interaction. This new framework will enable FEU to better meet the current needs of its customers, with the ability to efficiently adapt to customers' needs as they change over time. Underpinning the new framework is a new internally administered technology platform which will enable the business processes necessary to meet our commitment to our customers.

5.3.7.2 Customer Service Organizational Chart and Employee Table

The organizational structure of the Customer Service department as it will exist on December 31st, 2011 is shown below:

Figure 5.3-3: Organization Chart for Customer Service



[82] CCE CPCN project was approved by Commission Order No. C-1-10

[83] Strategic sourced relates to the in-sourcing of key elements of the customer service function and the continuation of outsourcing transactions than can be exercised efficiently and cost effectively externally. For example- customer statement printing is an activity that will continue to be outsourced. For the purpose of simplicity, the term "in-sourced" will be used throughout this application to refer to this transition.

This organizational structure will support the new Customer Service delivery model. The majority of the new hires for the Contact Centres and Revenue Cycle and Billing Operations will be recruited and trained during the latter half of 2011 in preparation for the transition, as a CCE Project activity.

Table 5.3-29: Changes in Staffing Levels Required to Support the Transition to an In-Sourced Customer Service Delivery Model

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	36	37	36	367	325	309
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	36	37	36	367	325	309

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	7	7	7	336	15	13
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	7	7	7	336	15	13

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	29	31	29	31	310	296
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	29	31	29	31	310	296

Note: The difference of sixteen employees in 2011 between the organizational chart and the employee table shown above represents the Centralized Support Service resources required from IT and HR to support the in-sourced Customer Service framework.

The 331 increase in 2011 from the approved level of employees represents the resources required to support the transition to the in-sourced Customer Service delivery model. During the second and third quarters of 2011, hiring of the Contact Centre and Revenue Cycle and Billing Operations management team will be complete, and in the last two quarters of 2011, the bargaining unit staff will be recruited and trained. During 2011, these additional resources will be engaged in the CCE Project and hence are shown here under the Capital / Deferral section.

An increase in proficiency will result in the need for fewer resources over time. Through the period of 2011 to 2013, increased proficiency is expected to result in the reduction of 58 employees. Throughout 2012, FEU expects that staff in the Customer Service department will become more proficient at their duties, including handling calls, addressing complex billing issues, managing call volume volatility, as a result of refinement in the end to end business processes. In addition, FEU has anticipated a shift of some inbound call volumes to less labour intensive channels such as e-mail, online chat and self serve.

5.3.7.3 Customer Service O&M Expenditures

The table below summarizes the approved, actual, projected and forecast O&M levels for the Customer Service department for the 2010 to 2013 period.

Table 5.3-30: Customer Service O&M Required to Meet Future Obligations

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 56,951	$ 53,292	$ 56,935	$ 56,935	$ 55,388	$ 58,959
Vancouver Island	$ 5,281	$ 5,025	$ 5,459	$ 5,459	$ 5,257	$ 5,599
Whistler	$ 151	$ 125	$ 156	$ 156	$ 146	$ 154
Fort Nelson*	$ 138	$ 135	$ 136	$ 136	$ -	$ -
Total	$ 62,522	$ 58,577	$ 62,686	$ 62,686	$ 60,791	$ 64,712

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

The 2010 actual expenditure for the Customer Service department was $3.9 million below the approved level; this was primarily due to lower bad debt expense of $3.1 million and lower CWLP contract expense of $0.5 million. The lower bad debt expense was the result of low gas commodity rates and warmer winter weather which translates into reduced gas throughput, while the lower CWLP contract expenditure was due to lower actual CPI and fewer customer additions than budgeted. The 2010 CWLP contract inflation estimate included a CPI forecast of 2.3 percent, whereas the actual CPI rate amounted to 0.3 percent. At the time of this Application, no variance to budget for cost items, including bad debt expense, is anticipated for the 2011 projected expenditure. Since bad debt expenditure is driven by a number of factors including economic conditions, it is too early in the year to ascertain the likelihood of a variance to budget for 2011 such as that experienced in 2010.

The 2012 forecast shows a decline of approximately $1.9 million from the 2011 approved amount, as savings are recognized with the transition to the in-sourced service delivery model. The move to the new CIS and contact centre technologies will provide efficiencies that are not achievable with the current outsourced arrangement. While FEU continues to recognize efficiencies with the in-sourced model in 2013, these efficiencies are offset by the disappearance of cost savings from the joint gas/electric manual meter reads in our shared service area with BC Hydro, as BC Hydro pursues its Smart Metering Initiative ("SMI"). As discussed below (under Meter Reading Services), FEU is seeking deferral account treatment due to the uncertainties with respect to this cost component.

FUNCTIONAL GROUPS AND KEY RESPONSIBILITIES

The forecast O&M levels required for the Customer Service department have been delineated into the functions of the department.

Table 5.3-31: Customer Service O&M Functional Areas to Support a New In-Sourced Framework

($ thousands)

Customer Service	2012 Forecast	2013 Forecast
Contact Centres (Burnaby and Prince George)	12,349	11,837
Revenue Cycle & Billing Operations	15,256	15,026
Customer Relations	4,297	4,420
Bad Debt Expense	4,541	4,547
Meter Reading Services	17,750	22,000
Administration	634	649
Total Customer Service	**54,828**	**58,479**
Centralized Support Services	**5,963**	**6,233**
Grand Total	**60,791**	**64,712**

The Customer Service department will receive Centralized Support Services from Information Technology ("IT"), Human Resources ("HR") and Facilities. The expenditures for these services will be incurred in the respective departments, but for this RRA, they have been included within the Customer Service department to illustrate the total impact of the new in-sourced customer service delivery framework.

CONTACT CENTRES

Critical to the in-sourcing of Customer Service activities is the set up of two new Contact Centre facilities, one located in Burnaby and the other in Prince George. The two facilities will be equipped and staffed to ensure all customer inquiries are handled by skilled and knowledgeable staff and in a timely manner. The Contact Centre group will also be responsible for customer interactions initiated through the new communications channels including enhanced telephony capabilities, online chat and integrated e-mail. The new customer service framework will enable the ability to support industry changes including the education of customers related to the new biomethane service offering and the integration of this energy alternative and potential new offerings in the future into our contact centre operations.

FEU will also offer enhanced customer communication self-serve options as part of its multi-channel strategy, including web self serve and Interactive Voice Response ("IVR") capabilities. These transactional capabilities will be available to customers upon implementation on January 1, 2012, although customer adoption rates are largely unknown at this time. FEU will promote the use of these alternatives to customers and monitor customer response and satisfaction related to their use in order to more accurately forecast future impacts. As alternate communication channels of engagement are introduced, it is anticipated that these will have an impact on existing communication channels, however, the extent to which this occurs is uncertain at this time.

FEU has used 2009 call volumes (1,012,568 calls) as the basis for its estimate for 2012 and 2013 staffing levels, as these were most representative of a three year call volume average for the period 2008 to 2010. A schedule showing call volume history has been provided in Appendix D-7. The model to support staffing levels assumes sufficient flexibility to support daily, monthly and seasonal volatility. This will be managed through a mix of full time, part time and auxiliary employees. The contact centre staff will be recruited in 2011, and will undergo a comprehensive training program to ensure they have the skills and knowledge to navigate the complex business processes of an energy utility. The majority of these new hires will be covered by the Customer Service Collective Agreement negotiated with COPE. The Customer Service Collective Agreement is distinct from the conventional COPE Collective agreement that has been established for the COPE employees in the rest of the organization, as it has been specifically designed to support the unique needs of staffing requirements in a contact centre and billing operations environment. These unique needs include flexible scheduling to support timely response across multiple communication channels including 24/7 support for critical calls.

Although FEU believes that the 2009 call volumes are a good indicator of call volumes for 2012 and 2013, there are uncontrollable events that can significantly increase the number of calls into the contact centre. For example, significantly colder weather and variability in gas commodity costs would increase the number of calls, as customers seek clarification on their energy usage or statement balance. The fluctuations in call volumes will be managed to the best of the ability of the contact centre management and staff within the 2012 and 2013 forecast O&M expenditure levels.

While the CCE Project is on track according to its planned schedule, the project team is still in the process of implementing the new CIS and therefore the detailed steps of the end to end processes have not yet been fully developed and tested. Furthermore, there will be new staff hired and trained to perform these new processes. The project team is undertaking a tremendous amount of effort in developing comprehensive recruiting and training programs but has limited insight into the pool of eligible applicants it will receive, and consequently how fast these new staff members will grasp their new duties, responsibilities and perform the new business processes.

In order to enhance productivity, measure and monitor the quality of service provided to customers, improve performance and build employee loyalty, both the Contact Centres and the Revenue Cycle and Billing groups will be supported by an integrated telephony platform that includes Quality Monitoring and Workforce Planning capabilities. A supporting Learning and Knowledge team will provide the capabilities for ongoing training and communication as well as maintaining a knowledge base application providing ready access to information and instructions for all key business processes.

The Learning and Knowledge group will manage the design, development and delivery of fundamental customer service skills, processes, policies and procedures. The Quality Assurance team will provide ongoing coaching and development programs to improve all contact centre service delivery and will play a significant role in monitoring contact centre performance along with creating a culture that prides itself on delivering customer service excellence. The Learning and Knowledge team will also be responsible for developing effective training materials and facilitator guides as one of the Project deliverables. These documents will then form the foundation from which to structure all ongoing training and knowledge transfer. This group will continue to build on this foundation as they seek to monitor effectiveness of training delivery programs and retention of material, and will continuously amend and adjust in order to ensure service excellence. The Workforce Planning group will be responsible for managing the scheduling and availability of appropriately skilled staff.

The 2012 forecast amount for the Contact Centre operations is $12.3 million, with a decline of $512 thousand in 2013 to $11.8 million. The 2012 estimate includes temporary resources that will not be required in 2013, as FEU anticipates its contact centre agents will become increasingly proficient at their roles as they gain "on-the-job" experience throughout 2012.

REVENUE CYCLE AND BILLING OPERATIONS

The Revenue Cycle and Billing team will be responsible for billing and payments, collections, management of third party contracts including meter reading, and will be located at the Burnaby Facility. They will provide support to the Contact Centre staff in resolving complex billing issues and escalations. Furthermore, they will be responsible for proactively identifying potential billing issues and contacting customers to rectify issues before they are escalated.

The billing function includes establishing and maintaining accurate customer rates and pricing, determining tax applicability, calculating usage based on specific equipment and installation characteristics, calculating charges and taxes based on usage, applying special charges and payments and formatting, and printing statements for delivery to customers. This group will be responsible for receiving and processing customer payment. While a large number of customers continue to send payment by mail, a growing number use electronic means, such as direct deposit or online payment through their financial institution's website. Collections activities by this group will include managing activities to secure payment of arrears balances on active accounts, including specific and timely messaging, notification and disconnection of services related to active customers. The collections function also includes the placement, reporting and recovery processes related to terminated account balances.

In addition, this group will be responsible for contract management, including managing the agreements specifically negotiated to support industrial and transportation customers; together with contracts in support of marketers providing commodity service to customers under the commercial and residential customer choice programs. Facilitated by the new CIS, this group will also have the ability to implement new rate structures as needed, including for example expanded support for new natural gas refuelling services for fleet vehicles. Another specific area of focus supported through the CCE Project is billing and reporting support for the biomethane service offering.

Resource estimates for the back office functions were compiled by utilizing information from the following sources:

- Historical call volume information;
- Volume of work undertaken in the back office over the last few years at the outsourced provider;
- Preliminary process information indicating how SAP processes may differ from existing processes; and
- Comparison of these estimates to several other utilities through informal discussions as a reasonableness check.

The following assumptions were used to arrive at these estimates:

- The historical call and work volumes were tracked accurately by the outsourced provider and that these volumes will not change significantly in 2012 or 2013; and
- The final SAP processes will not change significantly from the draft processes currently documented.

The use of a daily mechanism for administration of the basic charge was approved by the Commission as per Order No. G-2-11. This Order approved a change from a monthly to a daily administration and has no impact on the basic charge rate. The Order directed FEU to identify any cost savings associated with the change in administration. The continuation of the monthly administration would have increased development and implementation efforts for the new system. As such, while the daily mechanism has required little system development and configuration there are no material O&M savings that can be identified as a result of this change.

The 2012 forecast amount for this group is $15.3 million, with a decline of $230 thousand in 2013 to $15 million.

CUSTOMER RELATIONS

The role of the Customer Relations group is to manage customer relationships by identifying the needs and expectations of customers and ensuring operations and processes across all departments within the organization serve to optimize these customer expectations. The group will maintain customer relations as its primary focus and will play a key integration role between the Customer Service department and the rest of the organization in sharing the learnings and insights the department attains from the increased direct interaction with customers.

Areas of accountability and responsibility will include:

- Customer Service and communications management regarding rates and tariffs, customer accounts and billing. Investigation of customer issues presented to the BCUC, Better Business Bureau, Provincial MLAs and Company executives with a focus on achieving timely resolution for customers;
- Ensuring effective integration of processes between Customer Service and multiple departments across the organization;
- Customer Choice program management to oversee all operational aspects of the Customer Choice program, gas marketer relations and annual filings with the BCUC;
- Customer Research management to oversee and conduct research such as annual customer satisfaction and commitment studies and periodic customer end use studies, among others. This team will manage activities to secure customer feedback regarding their expectations for existing and potential new products and services to ensure service delivery and new product and service activities meet the expectations of our customers;
- Administering customer construction service requests by means of the Construction Services Contact Centre. These service requests include new service installations, service alterations and service abandonments (removals);
- Conducting root cause analysis to address cross-functional issues and service or process improvement opportunities. Leading cross-functional teams to complete situational analysis, develop business cases and deliver improvements for customers and internal operations; and
- Oversee the development of performance measures and ensure that Service Quality Indicators (SQIs) and Corporate Scorecard metrics are accurately measured and that

quality and productivity targets are met or exceeded. Please see discussion on Service Quality Measures below.

The 2012 forecast estimate for this group is $4.3 million and $4.4 million in 2013, with the $123 thousand increase year over year to account for labour inflation.

BAD DEBT EXPENDITURE

The bad debt expenditure will be managed by the Revenue Cycle and Billing group. The forecast estimate of $4.5 million for 2012 and 2013 is based on analyzing actual historical bad debt expenditure to arrive at a reasonable experience rate of 0.30 percent for FEU for both 2012 and 2013. This experience rate was then multiplied by the forecast revenue to arrive at the 2012 and 2013 forecast levels. FEU believes the historical bad debt expense is a good indicator of the expected level for 2012 and 2013.

METER READING SERVICES

FEU's intention has been to continue with joint gas/electric manual meter reading that combines meter reading for FEU and BC Hydro in order to take advantage of the benefits associated with the joint meter read for as long as that option is available. BC Hydro's commitment to move forward with its SMI deployment combined with the termination of the Client Services Agreement with CustomerWorks LP, which includes joint manual meter reading with BC Hydro conducted by Accenture, instigated the requirement for FEU to explore alternative meter reading solutions for 2012 and beyond and to develop an independent meter reading strategy. After exploring various options, FEU has reached agreements with both Accenture and BC Hydro directly, for the provision of manual meter reading services and supporting infrastructure for the 2012 calendar year which amounts to a total forecast amount of $17.8 million for 2012. Accenture will manage and deliver meter reading services as they have since 2002, and BC Hydro will provide the meter reading infrastructure which has supported FEU's meter reading over this same period.

The 2012 meter reading agreements with both Accenture and BC Hydro have a two-tiered pricing structure based on dual reads (gas and electric) and single (gas only) reads which take into consideration the anticipated deployment of smart meters under BC Hydro's SMI program. The 2012 forecast amount was determined under the assumption that BC Hydro would have its smart meters deployed and activated by the end of 2012, consistent with its current plans. In the event that deployment and activation proceeds on a slower timeline, the actual meter reading costs incurred by FEU would be lower than the forecast amount. If the SMI did not proceed in 2012, then FEU expects that the meter reading costs incurred in 2012 will be approximately $12 million. FEU believes any savings in its meter reading costs from forecast should flow back to customers and the converse should also hold true.

These meter reading agreements are in the best interests of our customers and FEU as they enable FEU to maintain the benefits of joint gas/ electric manual meter reads in the majority of FEU's service areas; moreover they mitigate the risk of designing, developing, testing and commissioning new meter reading processes and interfaces while the CCE Project is being executed. Meter reading services were extraneous to the decision to in-source strategic customer service activities and as such did not factor into the project's cost-benefit analysis. FEU will continue to explore options beyond 2012 as BC Hydro is scheduled to have completed full deployment of its smart meters by the end of 2012, and is not expected to require large scale manual meter reading services beyond that time. As such, FEU has estimated gas only manual meter reads for 2013 in the amount of $22 million, at a unit rate consistent with the amounts included in the agreements with Accenture and BC Hydro for 2012. FEU is finalizing its strategy as to best meet its meter reading requirements for 2013 and beyond.

In 2012 and 2013, FEU will be faced with business uncertainties with respect to meter reading as discussed above and it is both reasonable and in the interests of our customers, that FEU include variances in meter reading expenditures between the forecast and actual 2012 and 2013 levels in a deferral account, discussed further below in Section 5.3.7.4. FEU is seeking deferral account treatment for actual meter reading expenditure that falls either above or below the forecast spend of $17.8 in 2012 and $22 million in 2013.

CENTRALIZED SUPPORT SERVICES

Centralized support services will be provided primarily by three departments - HR, IT and Facilities, and details of these services are provided below. The forecast expenditure for these services, of $6 million in 2012 and $6.2 million in 2013, have been shown here, rather than in their respective departments, in order to illustrate the total impact of the new in-sourced customer service delivery framework.

Human Resources

HR will provide general HR and labour relations advisory services along with payroll and time administration for the Customer Service Department. This HR support currently exists during the project phase and these services will evolve after the January 1st, 2012 go-live date. The additional resources in HR to provide this support will be $444 thousand in 2012 and $378 thousand in 2013 and are described further in the following paragraph.

In 2012, $230 thousand will account for two HR Advisor positions, to support staff at the Prince George and Burnaby locations. These resources are required to ensure effective administration and management of employee relations, including labour relations compliance with employment laws and standards, interpretation and application of the collective agreement, recruiting, and performance management. In addition, $214 thousand will account for three positions required to ensure all employee data including pay, time, compensation and related provisions in the collective agreement are effectively administered and managed. In 2013, FEU anticipates efficiencies with the implementation of automated time entry in SAP, would enable the elimination of one position and reduce the 2013 O&M forecast by $66 thousand.

Information Technology

IT will support and manage the new CIS technology platform, by providing system applications support, on-going sustainment services, and management of the overall integrity of the data. These services amount to a total of $3 million in 2012, and $3.4 million in 2013. Further details of these services are provided below:

Software Maintenance and Support

IT's contractual obligations in support of the new Customer Service department are forecast to be $1.024 million in 2012 and an incremental $82 thousand in 2013. There are two specific costs drivers in this category that are generally attributable to annual licensing fees associated with software and for agreements with third parties for the support and maintenance of the Companies applications. First, licensing and annual maintenance for the CIS will drive an annual fee of $638 thousand in 2012 and an additional $73 thousand in 2013, factoring in fees related to customer growth projections. Third party consulting and support services enabling the CIS and Customer Contact Centre technology will drive $386 thousand in 2012 and $9 thousand in 2013.

Infrastructure

With the advent of Customer Contact Centre and Revenue Cycle and Billing Operations in 2012, the Customer Service department is expected to be highly reliant on information technology to deliver a stable and scalable operation, to drive efficiencies in its business operations and to continue service improvements for its customers. Information technology infrastructure will play a key role in achieving this mandate with the required infrastructure being delivered through the CCE Project in 2011. As such, in 2012 when the Project is completed and the delivered infrastructure becomes fully operational, IT forecasts an incremental $994 thousand to the existing operations support model for fees associated with the maintenance and support of this new infrastructure. In 2013, there is a reduction of $13 thousand to reflect the decommissioning of the equipment used by the Project office and the redeployment of the equipment into inventory for future usage or retirement as some of the equipment will have reached the end of its useful life.

Labour

As a centralized service organization charged with technological enablement of the new Customer Service department, IT must maintain an effective staffing level commensurate with the expectation of this new organization, core applications and business processes. This will better enable IT to respond to departmental and ultimately customer demands and to meet ongoing service delivery expectations. As such, IT forecasts incremental headcount for the Enterprise, Application and Infrastructure support teams to support the Customer Service department's business processes and supporting technologies. Specifically, the IT department requires additional headcount to bolster the key functions in customer self-serve, billing operations and technical support for IT infrastructure and software applications in production. In order to facilitate these functions, IT forecasts the addition of ten employees for a total of $988 thousand in 2012 with continued support to the Customer Choice program estimated at a combined resource of one employee. It is important to note that labour costs in 2012 represent three quarters of the year (April – December 2012) as the project stabilization period (January – March 2012) remains a charge to the CCE Project. As such, an incremental $310 thousand is required in 2013 to account for the full year.

Facilities

Facilities will be responsible for providing services ranging from building asset operation and maintenance, physical security, space planning, office furniture and equipment, mailroom and reception services for both the Burnaby and the Prince George facilities.

The 2012 funding request of $2.5 million is comprised of the following:

- Lease Contract expense of approximately $2 million for the Burnaby facility lease and parking;
- Service contracts and building maintenance are estimated at $225 thousand, and includes janitorial, landscaping, snow removal, carpet cleaning, security, HVAC maintenance, generator and UPS maintenance, pest control, electrical and fire extinguisher maintenance;
- Utility costs estimated at $185 thousand for electrical, natural gas and water; and
- Administration costs of $160 thousand for stationery, courier, postage, office equipment maintenance and first aid supplies.

For 2013, a $19 thousand increase is required to support inflationary increase in rent and electricity.

5.3.7.4 Deferral Account Summary for the Ongoing Operating Costs of the In-sourced Service Model

This section provides a summary of the ongoing operating costs of the in-sourced activities, with a comparison of the 2012 and 2013 forecasts to the preliminary O&M estimates supplied with the CCE CPCN application. As explained below, a deferral account is sought for variances from these forecasts due to the unique uncertainties related to the first years of operating under the new service model and technology platform.

Table 5.3-32: 2012 and 2013 Ongoing Operating Costs of the In-Sourced Service Model

($ thousands)

Ongoing Operating Costs of In-sourced Activities	2012 Forecast	2013 Forecast
Contact Centres (Burnaby and Prince George)	12,349	11,837
Revenue Cycle & Billing Operations	15,256	15,026
Customer Relations[a]	997	1,032
Total Customer Service	**28,602**	**27,895**
Centralized Support Services	5,963	6,233
Grand Total	**34,565**	**34,128**
Estimate supplied with CPCN Application[b]	**35,282**	**35,660**
Savings	**(717)**	**(1,532)**

[a] These services were identified in the CCE CPCN application as necessary to support the in-sourced activities

[b] These estimates correspond to the 2012 and 2013 O&M forecasts of $46.2 million and $47.5 million submitted with the CCE CPCN application before inclusion of manual meter reading costs.

Since the estimate was provided in the CCE CPCN Application, the forecast for ongoing operating costs of the in-sourced activities has been refined by drawing on the detailed functional design of the new CIS and the most current information from the CCE Project. The revised estimates are $0.7 million lower for 2012 and $1.5 million lower for 2013 than the estimates supplied at the time of the CCE CPCN application. The $0.7 million savings for 2012 is due to lower forecast centralized support costs and an additional $0.8 million savings in 2013 is primarily due to lower staffing requirements in the Contact Centres and Revenue Cycle and Billing Operations than was anticipated at the time of filing of the CCE CPCN application.

The operating cost estimates for 2012 and 2013, however, are subject to a number of uncertainties related to the first years of operating under the new service model and technology platform. The types of uncertainties include fluctuations in call volumes, the rate of customer adoption of new communication channels and self serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, along with a potentially longer than anticipated duration required for new staff to become skilled and proficient at their responsibilities.

As discussed above, although FEU believes that the 2009 call volumes are a good indicator of call volumes for 2012 and 2013, there are uncontrollable events that can significantly increase the number of calls into the contact centre. For example, significantly colder weather and significant variability in gas commodity costs would increase the number of calls, as customers seek clarification on their energy usage or statement balance.

As also stated above, the CCE project team is still in the process of implementing the new CIS and therefore the detailed steps of the end to end processes have not yet been fully developed and tested. Once the operating experience with the CIS and related processes is gained, FEU should be able to more accurately forecast operating expenditures.

In addition, there will be new staff hired and trained to perform these new processes utilizing the new CIS. The project team is developing comprehensive recruiting and training programs but has limited insight into the pool of eligible applicants it will receive, and consequently how fast these new staff members will grasp their new duties, responsibilities and perform the new business processes. Thus, while FEU anticipates that that there will be a reduction in the need for resources in 2013 as staff become more proficient at their roles with front-line experience, the extent of this reduction is difficult to estimate with accuracy.

Given these uncertainties, the Companies are requesting a deferral account to capture actual expenditures that differ from the 2012 ($28.6 million) and 2013 ($27.9 million) forecast O&M expenditure levels for the ongoing operating costs of the in-sourced activities. The FEU believe that any savings associated with the ongoing operations of the in-sourced activities should flow back to customers and the converse should also hold true.

In addition to the expenses shown above, this same deferral account will also capture variances in meter reading expenditures between the forecast and actual 2012 and 2013 levels as discussed in Section 5.3.7.3.

5.3.7.5 Service Quality Measures

The transition to an enhanced customer service delivery framework will enable FEU to exercise greater control over the processes and technologies that facilitate the Companies' ability to adapt to changes in the business environment and in customer expectations to ensure service quality is maintained and enhanced. FEU understands that service quality measures need to be revisited and refreshed to reflect customers' evolving needs, and the implications of technology changes which will support business process improvements. For these reasons FEU will be evaluating performance measures during the first year of operations, and will be assessing the appropriateness of the existing service metrics to ensure they are reflective of the business process changes along with overall customer expectations. Some of these metrics will be for internal review, as they will seek to monitor the efficiency of discrete business processes; while others will be more visible and measure the direct impact on customer service delivery. As such, FEU will continue to measure service quality through the existing Service Quality Indicators for 2012 and 2013, as described in Section 3.1.2.

5.3.7.6 O&M Expenditures for each Utility

The forecasts for each utility, presented below, have been derived by forecasting the direct costs for each utility, or identifying those costs that pertain to all utilities and allocating to the

Mainland, Vancouver Island and Whistler utilizing customer count as the allocation base. The use of customer count as an allocation base is consistent with the methodology that has been in use with the existing BPO arrangement. All changes in O&M expenditures for the Customer Service department (other than labour and benefit inflation on existing O&M employees) has been classified under the cost driver Customer and Stakeholder Expectations.

The O&M forecast changes from 2011 to 2012 are primarily the result of efficiencies achieved in transitioning Customer Service activities from a BPO arrangement to a in-sourced framework, as described above. The increase in 2013 is driven primarily by an increase in manual meter reading service costs as the benefits of joint gas/electric meter reads with BC Hydro disappear.

MAINLAND

The table below shows the Mainland's O&M expenditure changes from 2011 to 2013.

Table 5.3-33: Mainland Customer Service O&M requirements

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	56,935	(15)	120	-	(1,653)	-	-	(1,548)	55,388
2013	55,388	-	553	-	3,018	-	-	3,571	58,959

VANCOUVER ISLAND

The table below shows Vancouver Island's O&M expenditure changes from 2011 to 2013.

Table 5.3-34: Vancouver Island Customer Service O&M requirements

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	5,459	(3)	-	-	(198)	-	-	(201)	5,257
2013	5,257	-	-	-	342	-	-	342	5,599

WHISTLER

The table below shows Whistler's O&M expenditure changes from 2011 to 2013.

Table 5.3-35: Whistler Customer Service O&M Requirements

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	156	-	-	-	(10)	-	-	(10)	146
2013	146	-	-	-	8	-	-	8	154

FORT NELSON

The table below shows Whistler's O&M expenditure changes from 2011 to 2013.

Table 5.3-36: Fort Nelson Customer Service O&M Required

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012*	136	-	-	-	(136)	-	-	(136)	-
2013	-	-	-	-	-	-	-	-	-

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

5.3.7.7 Customer Service Summary

In 2012, FEU sees an evolution in the Customer Service delivery model, as it transitions to an in-sourced framework with direct control over customer points of interaction that will enable the Companies to better meet the expectations of its customers. The estimates prepared for 2012 and 2013, have drawn upon both historical data together with the most current functional design of the new CIS. However, the Customer Service department will be faced with business uncertainties that can only be identified, evaluated, and effectively managed once the in-sourced services are operational and the Customer Service staff have had "on the job" experience; and therefore it is reasonable, prudent and in the interests of our customers, that FEU request a deferral account to capture both actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for the ongoing operations of the in-sourced activities, and variances in the 2012 and 2013 meter reading costs.

5.3.8 ENERGY SOLUTIONS AND EXTERNAL RELATIONS

5.3.8.1 ES&ER Departmental Overview

FEU's Energy Solutions and External Relations ("ES&ER") Department has evolved during 2010 and 2011 from the Marketing and Business Development Department that existed at the time of the 2010-2011 RRA. The implementation of a new Customer Information System and in-sourcing of Customer Service activities[84] resulted in the creation of a new Customer Service department, which caused business activities between the two groups (ES&ER and Customer Service) to be realigned. Customer service and customer research activities were moved to the new Customer Service department, while customer information, education, energy solutions and business facilitation activities remain with the ES&ER department. For more information about the Customer Service department, please see the preceding Section 5.3.7.

[84] CIS implementation and in-sourcing of customer service activities was approved in February of 2010 by Commission Order No. C-1-10.

Functional groups within ES&ER are Market Development, Resource Planning and Market Assessment, Community, Aboriginal and Government Relations, Communications and Energy Solutions[85]. Included in the responsibilities of these groups are:

- Planning and implementing energy efficiency and conservation ("EEC") programs;
- managing customer energy solutions and key customer accounts;
- developing new initiatives and service offerings to meet customer needs;
- energy demand and customer forecasting and integrated resource planning;
- developing and executing customer, public and employee communication; and
- liaising with communities, First Nations, government and other stakeholders.

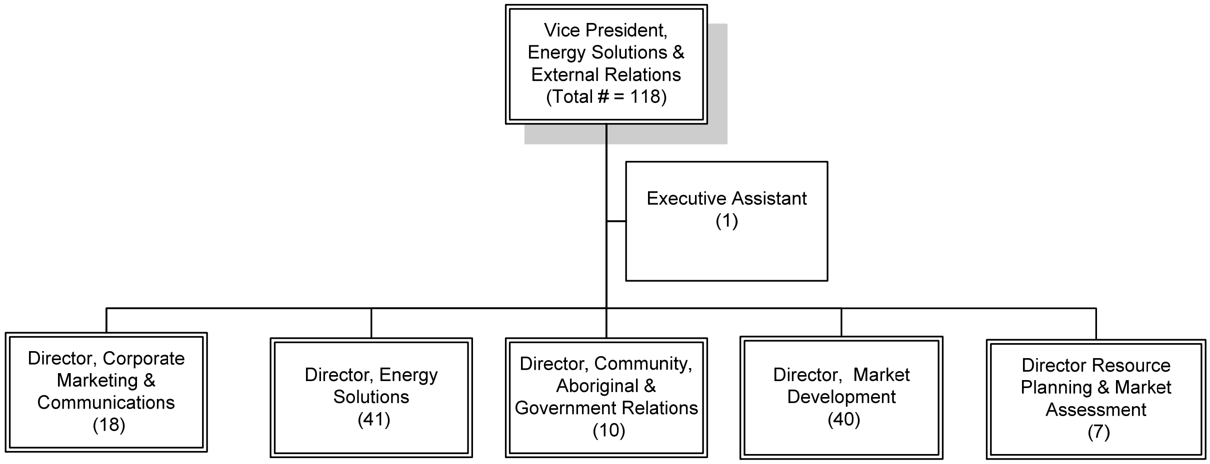
ES&ER ORGANIZATION CHART

Figure 5.3-4 shows the five major areas of responsibility within the Energy Solutions and External Relations department as discussed above. The numbers of employee positions shown within each group are projections to the end of 2011. Additional description of the activities of these groups follows. A number of 2010 and 2011 achievements for the ES&ER department are presented in Section 5.3.8.3.

[85] Thermal Energy Services is also a workgroup within the ES&ER department: however, all costs for this group are tracked in a separate deferral account and not recovered from natural gas customers for 2012 and 2013. The activities and cost for the Thermal Energy Services Group are discussed in Appendix G, but are not shown in Figure 5.3-5.

Figure 5.3-4: Organization Chart for ES&ER

Structured to Meet the Needs of Customers and Other Stakeholders



Note: The Market Development Group in this organization chart includes 17 employees whose costs reside in the Energy Efficiency and Conservation deferral account and are therefore not part of the O&M for ES&ER. This deferral account is discussed in more detail in Section 6.3.

CORPORATE MARKETING AND COMMUNICATIONS

This group is responsible for both internal and external communications strategies and standards as well as media relations. Initiatives undertaken by this group include the development and implementation of customer communications, safety education messaging, social media activity, traditional media plans, corporate awareness messaging and events.

ENERGY SOLUTIONS

Staff in this group manage customer relations and key customer accounts, develop and implement activities to add new customers and load, identify and help develop service enhancements and initiatives for existing customers, communicate directly with customers regarding service options and new service initiatives including EEC program opportunities.

COMMUNITY, ABORIGINAL AND GOVERNMENT RELATIONS

This group maintains ongoing relationships with communities and municipalities, First Nations and their support organizations, business associations and key government ministries and organizations that regulate the energy industry, health and safety, and the environment.

MARKET DEVELOPMENT

The Market Development group identifies and develops new energy service products and initiatives such as FEI's biomethane and NGV fueling service initiatives. This group also includes the Energy Efficiency and Conservation function which develops, implements and tracks progress on FEU's efficiency and conservation programs. Supporting activities in this group include monitoring and assessing technology developments, investigating new service initiative opportunities, developing project and tariff applications for submission to the BCUC, and monitoring energy policy and other utility activities within and outside of BC.

RESOURCE PLANNING AND MARKET ASSESSMENT

This group is responsible for energy demand and customer forecasting as well as the development of FEU's Long Term Resource Plan. Currently this group relies on resources from other parts of the Company to provide and analyse research and monitor the energy planning and operating environment in order to complete its tasks. For example, the implications of new legislation or efficiency codes and standards on customer demand for natural gas are an input into the demand forecast, while impacts of a growing marketplace for renewable thermal energy solutions have implications for FEU's long term planning strategies. The Energy Supply and Resource Development Department (see Section 5.3.6) also provides key inputs into the Long Term Resource Plan by continuously monitoring natural gas and propane supply issues and constraints, and assessing alternative solutions.

5.3.8.2 ES&ER O&M Expenditures Overview and Employees

Meeting customer and stakeholder expectations forms the foundation of many of the Companies' operating programs and activities. Table 5.3-37 sets out approved, actual, projected, and forecast O&M costs for ES&ER. These costs are reviewed later in this section.

Table 5.3-37: ES&ER Department Effectively Managing Continued Increased Expectations From Customers and Stakeholders

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 13,599	$ 14,280	$ 14,370	$ 14,370	$ 17,423	$ 18,439
Vancouver Island	$ 1,410	$ 1,329	$ 1,464	$ 1,464	$ 1,657	$ 1,694
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 15,009	$ 15,609	$ 15,834	$ 15,834	$ 19,080	$ 20,132

While 2010 Actuals have exceeded 2010 Approved amounts, FEU projects year-end expenditures to equal the approved amount for 2011, as discussed further in Section 5.3.8.3 and 5.3.8.4. Incremental funding requirements for 2012 and 2013 are explained in Sections 5.3.8.5 and 5.3.8.6.

ES&ER has M&E and COPE employees. The cost of those employees needed to support the activities of ES&ER is included in the O&M costs set out in Table 5.3-37 above. Table 5.3-37 does not include deferral account budgets for EEC and Thermal Energy Services, which are also part of ES&ER. Details of projected spending and requested funding for these deferrals are included in Appendix K along with supporting information for EEC spending and Appendix G for Thermal Energy Services. Table 5.3-38 sets out approved, actual, projected, and forecast employees for ES&ER.

Table 5.3-38: Modest Increases in ES&ER Staff to Continue Meeting Our Commitments to Customers and Stakeholders

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	91	105	95	110	117	117
Vancouver Island	7	6	8	8	8	8
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	98	111	103	118	125	125

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	10	16	10	17	17	17
Vancouver Island	0	0	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	10	16	11	18	18	18

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	81	90	85	93	100	100
Vancouver Island	7	6	7	7	7	7
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	88	96	92	100	107	107

Note: For the Capital / Deferral employee portion of the table, the heading “Approved” refers to the information presented in the 2010-2011 RRA as approved by the Commission, and does not refer to the 2008 EEC Program Application approval. The number of employees added to the EEC deferral account may vary as programs expand and customer activity increases. As discussed in Appendix K, the number of staff working on EEC initiatives will be managed within guidelines established as part of the 2008 EEC Program Application.

By the end of 2011, ES&ER expects to have increased its employees by 15 over that approved as part of the 2010-2011 RRA. Seven of these fifteen are related to Energy Efficiency and

Conservation activities as programs are developed and launched. These costs are captured in the EEC deferral account, and the associated employees are therefore not included in the O&M portion of the table. Three of the fifteen are included in the Customer Service Department in '2011 approved', but are moved into the ES&ER department in '2011 projection', therefore representing a transfer and not an actual increase in headcount within the company. Four new positions in the Energy Solutions group were created through a reallocation of approved budget spending to ensure the group continued to meet its commitments to customers. Finally, one position was created to manage the new biomethane service offering and was approved by Commission Order G-194-10 as part of a separate biomethane application discussed in Section 5.3.8.5 below. Other minor variances are caused by the accumulated impact of hiring for some new positions later than expected.

5.3.8.3 ES&ER 2010 and 2011 Review - Mainland

As discussed in our 2010-2011 RRA, government policies and regulations, along with public perception and changing energy price pressures, are all contributing to changes to the way that customers are using energy. Customer groups and other stakeholders told FEU that they wanted more service alternatives and energy solutions to help reduce emissions and manage energy cost pressures. As a result, the ES&ER department needed to increase its annual budget in order to undertake a range of new activities to meet evolving customer needs and a dynamic business environment. This increased spending was approved by the Commission and a number of new initiatives were implemented by FEU following the approval. Some of the accomplishments that this increased spending allowed include:

- New and expanded energy efficiency programs for 2010 and 2011 that will result in cumulative energy savings of over 700,000 GJs and associated GHG reductions;
- Bringing carbon neutral biomethane produced using local agricultural waste into the gas distribution system and developing a complete biomethane service offering for customers;
- Critical work toward the successful completion of negotiations for service agreements with a number of Vancouver Island municipalities;
- The development of new natural gas fueling service for fleet vehicles that will benefit all natural gas customers through increasing year-round loads on the gas distribution system; and
- The ongoing development of an integrated thermal energy service offering and project initiatives that will help customers reduce carbon emissions and manage energy costs over the long term, and for which utility spending has been segregated.

In 2010, the department had to manage more business activities than expected. Examples include greater than expected media coverage and public education about FEU's biomethane service offering, greater than expected social media activity, commodity rates education messaging, communications on natural gas solutions for transportation, and expanded event activity such as municipal conferences, industry events and builder association awards support. A communications and public affairs plan was also made a priority for funding reallocation and continues to be implemented. As a result, there was an increase in spending of $680 thousand in 2010.

Some offsetting spending reductions also occurred. These resulted from higher than expected cross-charging of staff time into the deferral account for thermal energy services development, and a longer than expected delay in hiring some of the new staff positions, until part way through 2010.

The 2011 Mainland O&M budget is also shown in Table 5.3-37. 2011 Mainland O&M costs for the ES&ER department are projected to remain at the approved level.

5.3.8.4 ES&ER 2010 and 2011 Review - Vancouver Island

On Vancouver Island, actual spending was lower than approved in 2010 due to cross charges made into the Thermal Energy Services deferral account as well as lower than expected costs for completing municipal operating agreements with a number of Vancouver Island municipalities. The 2011 projection remains consistent with the approved budget.

5.3.8.5 ES&ER 2012 and 2013 Forecast - Mainland

For 2012 and 2013, most of the activities that ES&ER will be undertaking, such as those described in Section 5.3.8.3 above, are the same as those undertaken in 2010 and 2011 based on the 2010-2011 RRA settlement agreement. For these activities, incremental spending in 2012 and 2013 is limited to inflationary pressures. Three important initiatives, however, do require additional incremental resources beyond inflation. One of these initiatives is the public safety education initiative which received some incremental funding for the 2010-2011 period, but requires additional funding to further implement our plan. The second initiative is a range of new activities stemming from the Commission's recent decision on the Companies' 2010 Long Term Resource Plan. The third is the approved ES&ER costs related to the Biomethane Service Offering for 2012 and 2013.

A fourth initiative, fueling service for NGV, is discussed in Appendix I. Budget details related to this initiative are presented in anticipation of a Commission decision on our Application for General Terms and Conditions for Compressed Natural Gas and Liquefied Natural Gas Service.

Table 5.3-39 summarizes the additional funding requirements for the Mainland ES&ER activities. Incremental spending is being driven by a range of cost drivers as explained in the following discussion.

Table 5.3-39: Incremental Mainland ES&ER Funding in 2012 - 2013

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	14,370	(4)	606	750	1,616	-	85	3,054	17,423
2013	17,423	-	489	100	299	-	128	1,015	18,439

CODES AND REGULATIONS

FEU has a responsibility to educate the public about the risks associated with its natural gas and propane products. Thus, FEU has developed safety education programming that is a critical part of the Mainland natural gas Safety Management Plan to meet the requirement of the CSA Oil and Gas Systems Standard Z662-07. Section 10.2 of the Standard indicates that operating companies must "develop, implement and maintain a documented safety and loss management system for the pipeline system that provides for the protection of people, the environment, and property".[86] FEU views public safety education as a key part of our safety and loss management system, and has thus developed a measuring and monitoring system to review the effectiveness of safety education activities.

Further, Annexes M and N of Z662-07 guide the development and implementation of integrity management systems for gas distribution and pipeline systems. Public safety education programs can reduce risk to the public, the environment and property by improving safety awareness, and can improve system integrity by reducing potential hazards caused by third party damage. Therefore, public safety education is also an integral part of FEU's integrity management system.

In 2010, the Companies added a single staff member and increased spending on public safety education, with one of the main objectives being to support safe, secure and healthy communities by increasing public awareness of gas safety risks and the steps that can be taken to minimize the potential for accidents and harm. While this increase in spending has shown positive results, research and statistics indicate that more needs to be done.

An additional $850 thousand annually is needed in the Mainland service area to build on and enhance the success of the public safety education programming established in 2010. This additional spending is necessary for two purposes: 1) to increase the public's understanding of safety issues and appropriate actions pertaining to natural gas odour; and 2) to improve excavation diligence and reduce third party damages to the natural gas system. Due to the timing required for ramp-up of safety messaging activities, Mainland estimates that the incremental cost in 2012 will be slightly less than the annual amount being requested for 2013. The 2012 incremental funding requested for public safety education is $750 thousand, with a

[86] Canadian Standards Association Standard Z662-07 Oil and Gas Pipeline Systems, June 2007, Section 10.2, page 177.

further $100 thousand requested in 2013. This funding will become part of the communications budget within the ES&ER department.

Approximately two thirds of the incremental funding requested for public safety education is expected to be spent on gas odour and action awareness in 2012 and 2013 in addition to current activities. In the 2010-2011 RRA, FEU requested and received approval for $1.0 million in safety awareness spending, primarily to increase the public's awareness of how to identify and respond to a gas leak. Vital to public safety preparedness is ensuring the public knows the proper order of steps to take when dealing with a gas leak. The 2010 campaign has been successful in raising the awareness of how to recognize a gas leak (via its odour) and some of the actions that need to be taken in a gas odour emergency. Research indicates that public awareness of some individual messages increased by between ten and fifteen percent. Recalling all of the messages and the order in which to take appropriate action in the event of a gas leak is much more complex.

The effectiveness of the complete FEU gas odour and action safety messaging (knowing the signs of a possible gas leak and the correct order of actions to take) is measured using a Safety Preparedness Index. This index showed a 5 percent improvement over pre-2010 conditions to a full awareness level of 15 percent. With a target awareness level of at least 50 percent, more funding is required to build on the success to date. Since message clarity, frequency and repetition are all important factors in raising issue awareness, both the increased spending and more time over which to run the education programming are required to reach more satisfactory awareness levels.

The remaining third of the incremental funding for increased public safety education is for excavation diligence (call before you dig). Table 5.3-40 shows that the number of third party damage incidents in each the past 5 years decreased from 2007 to 2009 and then seems to have levelled off. Each incident represents a potential risk to public safety.

Table 5.3-40: Third Party Damage Incidents Decrease and then Level Off

Year	2006	2007	2008	2009	2010
Number of Incidents (all service regions)	1751	1881	1661	1435	1448

The public education programming will work with other safety and system integrity initiatives such as the damage prevention workshops that target excavation contractors as discussed in Section 5.3.5.3. Our education programming will also complement the BCOneCall public awareness campaign, which, on its own, has been insufficient to adequately reduce third party damage incidents. Approximately 30 percent of the requested funding increase will be used for excavation diligence education. A small portion of the budget (approximately 5 percent) will be used to bolster our current gas appliance safety, winter preparedness and gas meter safety messaging.

The additional funding of $750 thousand in 2012 and $850 thousand in 2013 will bring FEU's annual safety education spending during the test period closer to $2 million, or approximately $2 per customer, annually.

CUSTOMER AND STAKEHOLDER EXPECTATIONS

ES&ER will require $1.616 million in 2012 and a further $299 thousand in 2013 in support of the forecasting, research and integrated resource planning activities and the Biomethane service offering.

FORECASTING, RESEARCH AND INTEGRATED RESOURCE PLANNING

FEU's stakeholders[87] are seeking a much greater depth of research and analysis in our long range planning efforts than we currently have the capacity to provide. Feedback from these stakeholders during the regulatory process for the 2010 Long Term Resource Plan ("LTRP") highlights the growing need for new analyses and a broader examination of potential future outcomes. In consideration of these needs, the Commission's decision on the 2010 LTRP together with Commission Order No. G-14-11 requires FEU to comply with a number of related directives. Currently, our integrated resource planning function has very few resources[88] that can be dedicated to these activities. Therefore, In order to comply with these directives and to implement additional initiatives that will improve FEU's integrated resource planning, we are requesting an annual budget increase of $1.5 million, including an additional 7 employees.

Anticipating a ramp-up period in early 2012 for hiring staff and initiating the needed research and analytical activities, the 2012 funding request is $1.2 million, with an incremental $300 thousand in 2013 for a total annual funding of $1.5 million. Table 5.3-41 provides an explanation of the requested incremental funding in relation to the Commission's directives and new FEU initiatives related to our long range planning activities.

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87 Stakeholders include municipal and provincial governments, First Nations, customer and environmental advocacy groups, energy industry participants, other utilities and the Commission.

88 Currently, 1 full time employee and one shared analyst position are dedicated to the preparation of the Long Term Resource Plan.

Table 5.3-41: Additional Resources are Required to Comply with Stakeholder Expectations and Commission Directives Related to Long Range Planning

<table>
<tr><th>Commission Directive / FEU Initiative</th><th>Incremental Budget Item and Description</th></tr>
<tr><td>20 year vision
- Macro-economic analysis and scenario development / review
- Market transformation scenarios
- Contribution to GHG reductions
- New technology forecasting
- Impact on BC Energy Objectives
- Drivers for non-EEC/infrastructure resource requirements</td><td>- Staffing for increased economic research, analysis and reporting
- Staffing for increased technology research, analysis and reporting
- Staffing for increased energy use and GHG modelling, analysis and reporting
- Funding for economic studies and reports, access to economic forums
- Funding to support market access and transformation studies, reports and analysis
- Staffing and activities associated with investigating non-EEC/infrastructure resource requirements</td></tr>
<tr><td>New Stakeholder Consultation Initiatives
- Resource Planning Advisory Group, Community Consultation Activities and other new consultation activities</td><td>- Staffing for planning, preparing for and executing increased stakeholder activities
- Funding to carry out increased stakeholder activities
- Staffing and funding to respond (within reason) to stakeholder requests and feedback during the long range planning process</td></tr>
<tr><td>EEC Planning and Impacts of New Initiatives
- GHG impact modelling and analysis
- Improved analysis of long term EEC planning and scenarios
- Impact of new service initiatives on EEC scenarios, resource requirements, demand and emissions</td><td>- Staffing for increased energy use and GHG modelling, analysis and reporting
- Staffing for increased analysis of long term impacts of EEC scenarios on other resource requirements
- Staffing to examine potential new service initiatives and analyze impacts
- Funding for increased research into and review of technology advancements affecting energy use</td></tr>
<tr><td>Planning Environment and Demand Forecasting
- Develop end-use forecasting methodology
- Compare with traditional methodology and prove out new methodology pros and cons
- Broader consideration of economic inputs to and impacts of planning scenarios
- Incorporate potential legislative, regulatory or market transformational changes into forecast and resource assessment
- Rigorous analysis of scenarios that consider the impact of new service initiatives on resource needs, energy demand and GHG emissions
- Consideration of other variables that could impact scenarios and results
- Regional / provincial thermal energy demand investigations
- Regional / provincial transportation energy demand investigations</td><td>- Staffing to develop new end-use forecasting methods, prepare and report on new forecasts
- Staffing to compare new and traditional forecasting methods and processes
- Staffing for increased consideration of economic variables in developing future scenarios and considering impacts on energy use and resource needs
- Staffing to examine alternative legislative, regulatory and market future scenarios in regard to energy demand, EEC, new initiatives and other resources
- Staffing to investigate thermal and transportation energy demand on a regional and provincial scale
- Funding to support additional staffing and forecasting initiatives</td></tr>
<tr><td>New report and document preparation requirements</td><td>- Staffing and funding support for communicating issues and analysis results and for including the increased long-range analysis and scenario considerations within the LTRP</td></tr>
</table>

FEU intends to ramp up its research, analytical, planning and consultation capabilities in response to these expectations as soon as approved funding is available. This should facilitate an anticipated LTRP filing in the first half of 2013. Any changes made to this level of funding will reduce the extent to which FEU is able to meet these Commission directives and expectations from customers.

BIOMETHANE SERVICE OFFERING

On December 14, 2010, the Commission issued Order No. G-194-10 in FEI's Application for Approval of a Biomethane Service Offering and Supporting Business Model (the "Biomethane Application"). The program was approved on the basis of a two year pilot period, which requires FEI to provide a comprehensive report on the program at the conclusion of the pilot. FEI is planning to launch the program in June of 2011.

In Order No. G-194-10, the Commission directed FEI to "Include in its next Revenue Requirements Application, in accordance with this Order and the Decision, details of costs for all deferral accounts created by this Order". The requested details are provided in Appendix J, which describes the pending launch of the Biomethane Service Offering and the actual, projected and forecast costs.

The Biomethane Application proposed to allocate and recover the costs of making the program available to customers, such as program administration and customer education, to all non-bypass customers, and that the costs for 2010 and 2011 would be collected into a deferral account but that, starting in 2012, these costs would be included in delivery rates. The proposed treatment was approved.

The incremental costs included in this RRA equal what was identified on page 3 of Appendix G in the Biomethane Application, with a total of $416,384 in 2012. Of these costs, $10,000 is a one-time cost and the remaining $406,384 was increased by a 2 percent inflation factor to determine a requirement of $414,512 for 2013. These costs include items such as customer education, program management and small improvements to the new CIS software. These costs are broken down in detail in Appendix J.

SERVICE STANDARDS AND RELIABILITY

The costs for service standards and reliability shown in Table 5.3-39 relate to non-labour inflation costs. These include inflation on items such as employee expenses, service and outsourcing contracts with third parties, sponsorships and memberships.

5.3.8.6 ES&ER 2012 and 2013 Forecast - Vancouver Island

Table 5.3-42 summarizes the additional funding requirements for the Vancouver Island ES&ER department. Incremental spending is mainly related to the Codes and Regulations driver as discussed below.

Table 5.3-42: Codes and Regulations Drive Most of the Incremental Funding Requirements for ES&ER Needs on Vancouver Island

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	1,464	(1)	37	150	-	-	7	193	1,657
2013	1,657	-	30	-	-	-	7	37	1,694

CODES AND REGULATIONS

Section 5.3.8.5 describes FEU's public safety education initiative and required incremental funding in relation to CSA Standard Z662-07. Our statistics show that the awareness level of how to recognize gas odour is somewhat lower on Vancouver Island than in the Mainland service area. Since recognizing gas odour is the first step in identifying and acting on potential natural gas hazards, it provides an important foundation for the entire gas odour and action education initiative. For this reason, an incremental annual funding amount of $150 thousand is requested specifically for public safety education programming on Vancouver Island.

5.3.8.7 ES&ER Summary

Incremental funding in the ES&ER department for 2012 and 2013 is set against important safety code requirements, and Commission directives and stakeholder expectations. Without these increases, FEU will not be able to meet its public safety education and long range planning obligations. Continued concerns with the state of the public's knowledge of natural gas safety and the implications for the well being of customers, the public and the environment warrant additional attention to public safety awareness education. As well, the changing planning environment and evolving customer needs require additional staffing and funding resources to examine a much broader scope of future long range planning scenarios and uncertainties.

5.3.9 INFORMATION TECHNOLOGY

5.3.9.1 IT Departmental Overview

The IT department is a centralized service group that is responsible for identifying, designing, operating, and maintaining technology solutions to improve the delivery of service. The services encompass three core functions: IT Infrastructure Management, Applications Management and IT Project Portfolio Planning and Execution.

INFRASTRUCTURE MANAGEMENT ("ITI")

ITI manages the overall technology environment and infrastructure architecture for FEU. This team is responsible for the plan, forecast and design of future infrastructure capacity requirements that will ultimately support the development and direction of implementation of new technology services at FEU. This team also ensures the availability, integrity and security of FEU's critical enterprise infrastructure including hardware and networks.

APPLICATION MANAGEMENT SERVICES ("AMS")

AMS manages the overall data and application architecture for FEU and provides application integration design and delivery services. AMS also is charged with supporting and managing existing applications and on-going sustainment. This team provides application architecture and technology advisory services and ensures application projects are developed according to our technology standards.

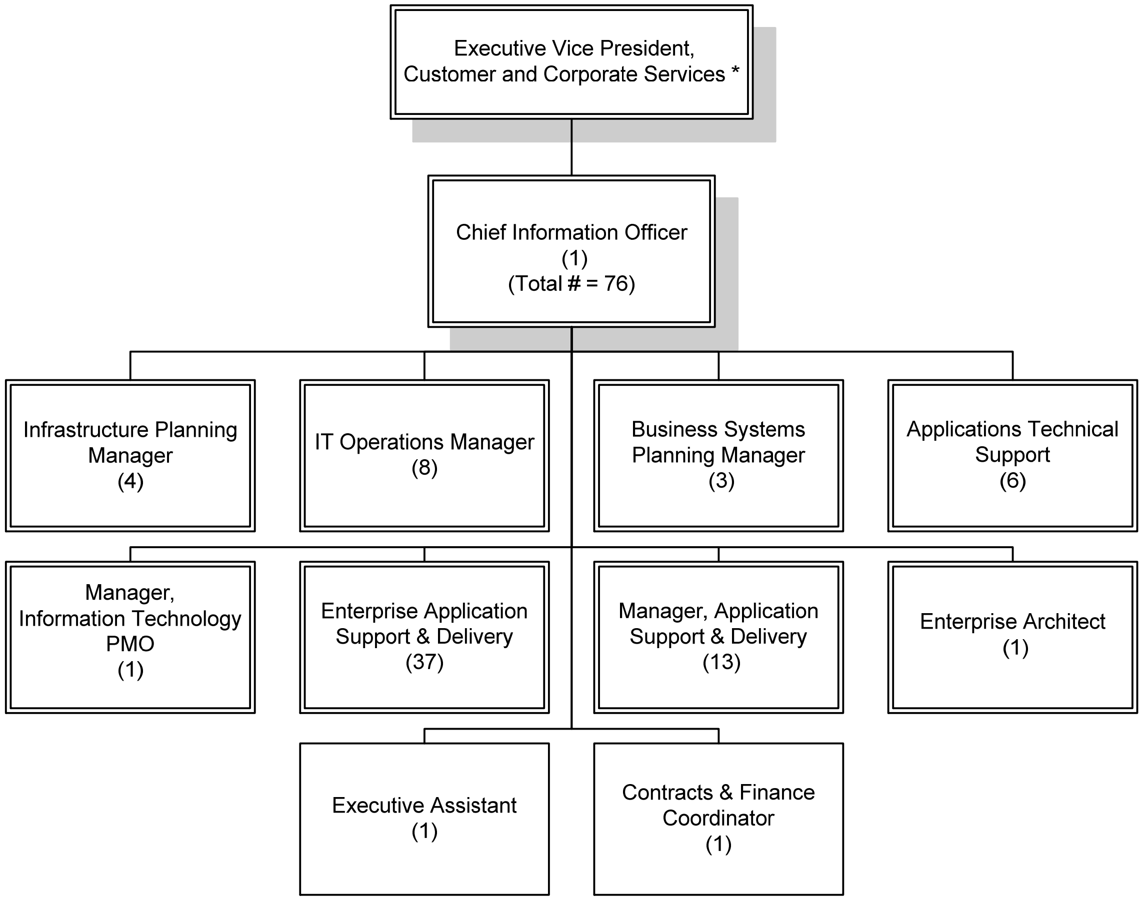
THE IT PROJECT PORTFOLIO PLANNING AND EXECUTION

The IT Project Portfolio Planning and Execution team supports the establishment and facilitates the implementation of the IT Project Portfolio that encompasses all of the capital project work undertaken by IT each year. This Portfolio is comprised of all project requests stemming from IT and many other FEU departments and it is established and executed under a governance process called IT Project Portfolio Management that is further examined in Section 6.2.

INFORMATION TECHNOLOGY ORGANIZATION CHART

The organization chart for the IT department is presented below.

Figure 5.3-5: Organization Chart for Information Technology



5.3.9.2 IT O&M Expenditures and Employees

To continue to identify, operate and maintain technology solutions in support of the FEU Companies, IT forecasts incremental O&M funding and employees in 2012 and 2013 primarily in the Service Standards and Reliability category. Some of the key drivers of this increase are contractual obligations, corporate growth, incremental O&M related to IT capital expenditures, and incremental labour costs related to the continuation of our in-sourcing of key IT sustainment functions. Table 5.3-43 sets out approved, actual, projected, and forecast O&M costs for the IT department. These costs are reviewed later in this section.

Table 5.3-43: IT Department O&M Increases to Maintain Service Standards and Reliability

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 18,353	$ 17,012	$ 20,095	$ 20,095	$ 21,505	$ 22,270
Vancouver Island	$ 423	$ 387	$ 421	$ 421	$ 422	$ 426
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 18,776	$ 17,400	$ 20,516	$ 20,516	$ 21,927	$ 22,696

The costs of IT employees (M&E and COPE) are included in the O&M costs that are set out in Table 5.3-43 above, as well as being included in IT capital projects. Table 5.3-44 that follows sets out approved, actual, projected, and forecast employees for IT.

Table 5.3-44: Employees Supporting IT Department Operations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	63	66	63	65	74	75
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	64	67	64	66	75	76

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	6	10	6	6	9	9
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	6	10	6	6	9	9

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	57	56	57	59	65	66
Vancouver Island	1	1	1	1	1	1
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	58	57	58	60	66	67

As a centralized service organization charged with IT enablement for FEU, IT must maintain an effective staffing level commensurate with the broader organization. This will better enable IT to respond to other FEU departmental demands and to meet ongoing service delivery expectations.

The IT operating model for FEU is a hybrid model of internal resources and third party service providers. The balance between what functions are managed internally vs. provided by external resources is a complex combination of factors including:

- Skills;
- Labour market conditions – both for the ability to attract qualified employees as well as the evolving business models of third-party service providers;
- The evolution of IT capabilities planned for the enterprise which in turn drives support requirements and new or different skills – both required and in some cases, no longer required; and
- Succession planning requirements.

It is part of our ongoing management role to review these factors and determine the appropriate balance of internal vs. external resources. IT will continue to change the mix of in-sourced vs. outsourced staff to ensure value for the customer and FEU.

For 2012 to 2013, a number of strategic, high-value IT development and support functions currently conducted by vendor partners or external consultants are being brought back in house in areas where it offers value for the customer. This reinvestment in IT's internal capabilities will reduce the loss of core knowledge and expertise and likewise will lead to increased scalability and versatility of the internal team. Through strategically sourcing services, IT is able to balance service levels, skills, internal knowledge and costs, and as market conditions change, adjust the support offerings accordingly. This will have the effect of increasing output against the fixed budgets due to the lower cost of labour taking on this work. Furthermore, IT will be able to leverage the continued offset of future consulting dollars coupled with resource capitalization rates and offsetting O&M related to capital projects to allow for a reestablishment of key functions like Business Analysts, Geographical Information System (GIS) Support Analysts, Project Manager and Infrastructure Support primes without a significant cost to the organization. In fact, the addition of 9 employees in 2012 and the 1 employee in 2013, as shown in Table 5.3-44 above, will result in an incremental cost of $89 thousand in 2012 and an incremental cost of only $40 thousand in 2013.

5.3.9.3 IT 2010 and 2011 Review - Mainland

Throughout 2010, the IT department realized approximately $1.3 million lower O&M than approved. This variance was seen in the areas of labour, consulting costs, and software.

IT experienced approximately $630 thousand less O&M attributable to labour and associated expenses. Across the team, several planned employee positions were hired later than initially forecast in the 2010 plan and there was higher than anticipated turnover of employees with some roles taking a long time to refill. In addition, due to project commitments in 2010, specifically the addition of the CCE Project, which was approved subsequent to finalization of the IT department O&M, much of the team was focused on delivery and did not fully utilize the dedicated expenses budget, which is inclusive of training. IT believes that maintenance and improvement of team members' core skills is vital to the department's continued success. As such, IT will place continued emphasis on the investment in employee training while limiting any impact on the commitment to delivery.

In 2010, IT experienced approximately $283 thousand less O&M attributable to its consulting costs. First, IT sought to put a greater emphasis on in-sourcing a number of previously outsourced high-value sustainment functions, thereby reinvesting in internal capabilities and reducing the loss of core knowledge and expertise. This in-sourcing initiative allowed IT to hire or retrain staff to support these critical functions but at a cost less than the contract, and it also allowed for a greater degree of flexibility. These permanent savings have been redeployed within IT Operations in order to minimize the incremental growth requirements in 2011 and to offset any further pressures that may arise in 2011. Second, IT was also able to forgo planned security testing expenditures in 2010 since this was already conducted as a part of the 2010 Olympic preparation. However, this cost is expected to be incurred in 2011 with planned security testing. Third, several planned maintenance costs were not required in 2010 based on IT taking the decision to pre-buy several extensions in maintenance arrangements, thereby reducing risk to the organization in the longer term. Finally, an minor increase in SAP consulting costs offset the above variances.

There were some very specific one-time opportunities related to software in 2010 that drove lower O&M of approximately $360 thousand. These included the elimination of PST mid-year (returned to customers through the Income Tax Variance deferral account), savings related to the US dollar conversion and inflationary savings on several contracts with software companies, and finally the pre-buying of software licenses and maintenance plans for infrastructure administration and security software.

The IT department anticipates that its 2011 spending will be in line with approved.

5.3.9.4 IT 2010 and 2011 Review - Vancouver Island

IT O&M costs in 2010 were slightly below approved. The IT department anticipates that its 2011 spending will be in line with approved.

5.3.9.5 IT 2012 and 2013 Forecast - Mainland

In order to continue to identify, operate and maintain technology solutions in support of the FEU Companies in 2012 and 2013, IT forecasts incremental O&M funding for Service Standards and Reliability. Some of the key drivers of this increase are contractual obligations, corporate growth, incremental O&M related to IT capital expenditures, and incremental labour costs related to the continuation of the strategic in-sourcing initiative.

As shown in Table 5.3-45 below, O&M expenses increase for the Mainland area by approximately $1.4 million in 2012 and by $765 thousand in 2013 primarily in the Service Standards and Reliability category.

Table 5.3-45: Mainland O&M Increases to Maintain Service Standards and Reliability

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	20,095	(185)	233	4	-	-	1,358	1,410	21,505
2013	21,505	-	290	-	-	-	475	765	22,270

SERVICE STANDARDS AND RELIABILITY

Incremental O&M related to Service Standards and Reliability totals approximately $1.4 million in 2012 and a further $475 thousand in 2013. These increases are driven by IT contractual obligations, growth in staffing levels, and business-driven initiatives for IT projects.

IT contractual obligation increases are driving an increase of $213 thousand in 2012 and $104 thousand in 2013. There are three areas that are generally attributable to annual licensing fees associated with software and for agreements with third parties for the support and maintenance of the Company's applications. First, changes in the SAP software licensing model are driving an increase of $17 thousand in 2012 and $40 thousand in 2013. Specifically, SAP has changed its licensing costs to 22 percent from 17 percent but introduced a graduated annual licensing increase for licenses that were already owned by customers. This graduated scale should reach the full 22 percent by the end of 2015. Second, contract and other inflation accounts for a $48 thousand increase in 2012 and $61 thousand in 2013. This includes TELUS contract inflation along with other software vendors such as Oracle and GE Smallworld. Finally, $148 thousand in 2012 and $3 thousand in 2013 is to purchase software under multi-year support contracts.

As a centralized service department, IT is required to support the projected growth and maturation of the FEU. As such, $92 thousand in 2012 and $12 thousand in 2013 is required to support increased Company-wide headcount, increases in infrastructure to support the new applications, upgrades to capacity for existing infrastructure as well as the ever increasing costs of security. Furthermore, as detailed in the discussion on IT Department employees in Section 5.3.9.2, the addition of 9 employees in 2012 and 1 employee in 2013 as shown in Table 5.3-44, will result in an incremental cost of $89 thousand in 2012 and an incremental cost of $40 thousand in 2013.

In 2010, FEU implemented accounting changes that altered the IT project capitalization policy. Certain costs that had been traditionally capitalized were required to be expensed. These included any costs incurred in the development of feasibility studies, business cases, training, training material, change management and general administration costs. At the time the accounting change was implemented, there were no costs captured specifically in these categories to provide quantitative evidence of this cost for forecast purposes, so it was estimated that these costs would amount to approximately 5 percent of the capital spend, with the assumption re-evaluated after the accounting changes were implemented in 2010 and 2011. Based on an analysis of 2010 actuals and considering the 2011 IT Project Portfolio, IT has calculated that 10.5 percent is required to effectively execute the planned capital spend. As such, IT is forecasting O&M related to capital projects at $2.1 million in each of 2012 and 2013 (10.5 percent of the planned $20 million of IT capital). This is an increase in 2012 of $920 thousand from the 2011 approved of $1.18 million.

Furthermore, the speed and complexity with which the IT industry moves offers a constant challenge to the IT department to maintain pace with industry changes, customer and internal expectations while ensuring prudent expenditures and business value. There are ever increasing security threats and increasing requirements for department support services. As such, $44 thousand in 2012 and $225 thousand in 2013 is required to support the incremental operating expense associated with new IT capital initiatives to address these requirements. These initiatives will include continued support to the Infrastructure Evergreen programs, ensuring sufficient and scalable data protection and storage, combined with the planned replacement of employee IT equipment. Additionally, IT will be seeking to consolidate and upgrade the Enterprise Messaging[89] and telephony infrastructures, specifically Microsoft Exchange and Communication Server upgrades, and the consolidation of email and voice mail through Unified Communication[90] technology. Some expenditures are required to support upgrades in network security infrastructure, replacement of aging network equipment and to enable the increased use of wireless networking. Finally, the biannual validation of the Disaster Recovery environment ensuring stability, performance and effective functioning will commence in 2013 driving an expected cost of $94 thousand.

5.3.9.6 IT 2012 and 2013 Forecast - Vancouver Island

As shown in Table 5.3-46 below, Vancouver Island O&M expense forecasts for 2012 and 2013 are consistent with 2011 projections.

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[89] Enterprise Messaging is our system that enables program-to-program messaging between applications and systems throughout the enterprise. It is a software interface that enables data (messages) to be sent by one program and stored in a message queue until the receiving program is able to process it.

[90] Unified Communications is a combined software package that includes voice mail, email, Voice over IP and other software communication enablers.

Table 5.3-46: Vancouver Island IT O&M Stable in the Forecast Period

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	421	(0)	1	-	-	-	-	1	422
2013	422	-	4	-	-	-	-	4	426

5.3.9.7 IT Summary

IT is constantly examining all of the above impacts and business requirements to find the appropriate balance of cost, risk mitigation and service. The forecast incremental IT expenditures are required in order to prudently manage, maintain, and support the IT infrastructure of the Companies to meet the goal of servicing the customer.

5.3.10 OPERATIONS ENGINEERING

5.3.10.1 Operations Engineering Departmental Overview

The primary focus of the Operations Engineering department is on technical compliance, achieved through the following areas.

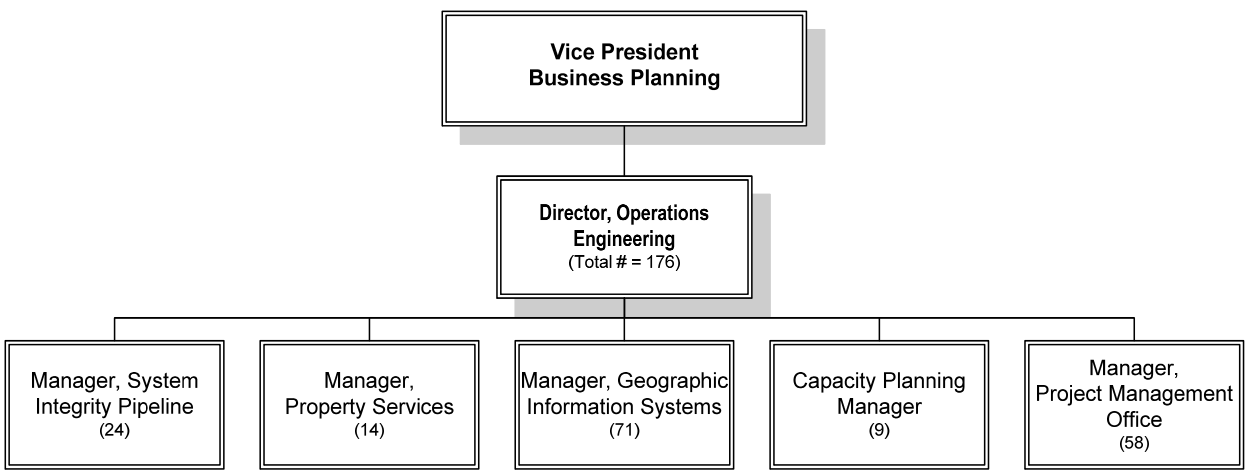
- The Project Management Office is responsible for the complete delivery of all capital projects related to pipelines and above ground facilities to meet the business needs of the transmission and distribution assets. The group provides project management, design services and drafting services to the FEU;
- The GIS area is responsible for completing new mains and service construction drawings and as-built mapping. It is also responsible for developing and maintaining the GIS base mapping system and maintaining the majority of the records for distribution and transmission facilities;
- System Integrity provides risk-based integrity management services related to operating plant and surrounding natural hazards, principally focused on material defect, corrosion, geotechnical and hydro-technical risks, and manages the TPIP on behalf of the Transmission group;
- The Corrosion group operates and maintains the systems providing cathodic protection ("CP") to operating plant;
- Property Services is responsible for managing all land rights and land tenure issues including property taxation, acquisition and disposal, leases, right of way ("ROW") agreements, and for supporting environmental reviews and First Nations negotiations;

- System Planning is responsible for the planning of the lowest cost system improvements for the gas distribution and transmission systems based on system hydraulics and for providing hydraulic scenario analysis for operational enquiries and project development;
- Location Records provides asset information for underground facilities, as requested through BCOneCall; and
- The Gas Lab provides gas measurement and analysis to ensure appropriate levels of odorization of the natural gas that is delivered to customers.

OPERATIONS ENGINEERING ORGANIZATION CHART

The Operations Engineering organization chart is presented below.

Figure 5.3-6: Organization Chart for Operations Engineering



5.3.10.2 Operations Engineering O&M Expenditures and Employees

Codes and regulations compliance and maintenance of service standards forms the foundation of many of the Operations Engineering departmental activities. Table 5.3-47 sets out approved, actual, projected, and forecast O&M costs for Operations Engineering. These costs are reviewed later in this section.

Table 5.3-47: Operations Engineering O&M

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 12,355	$ 12,355	$ 13,288	$ 13,288	$ 14,076	$ 14,633
Vancouver Island	$ 683	$ 983	$ 679	$ 679	$ 677	$ 677
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 13,038	$ 13,338	$ 13,967	$ 13,967	$ 14,753	$ 15,310

Operations Engineering has historically met its O&M targets and is forecasting prudent and reasonable increases in its 2012 and 2013 funding requirements going forward. For the Mainland region, Operations Engineering was on budget in 2010 and is projecting to be on target again in 2011 as detailed in Section 5.3.10.3. For the Vancouver Island region, Operations Engineering was allocated $300 thousand of internal funding in 2010 for the Vancouver Island Conflation Project. This was a one-time project for the Vancouver Island region where we updated our outdated municipal GIS landbase and shifted our gas infrastructure representation in GIS to align with the new and current municipal GIS landbase. Further information on this project is included in Section 6.3. For future years, Vancouver Island's forecast funding requirements return to their previous levels. For the forecast period, the additional funding requirements for the Mainland region are detailed in Section 5.3.10.4 below.

Table 5.3-48: Employee Profile Reflects Need to Sustain and to Meet Growing Regulatory and Strategic Requirements

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	164	160	172	176	191	191
Vancouver Island	2	1	2	2	2	2
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	166	160	174	178	193	193

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	47	52	48	56	64	64
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	47	52	48	56	64	64

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	117	108	124	120	127	127
Vancouver Island	2	1	2	2	2	2
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	119	109	126	122	129	128

On a total and O&M employee basis, the values for 2010 in the above table show significantly lower actual employees than the approved values because of the use of "seasonal staff". While these "seasonal staff" are approved and reflected in the Operations Engineering budget, they are filled from the temporary pool of staff whose employee count resides in Human Resources. (Refer to Section 5.3.13.3 for a more detailed discussion on this matter).

Other than this anomaly, Operations Engineering has consistently met its employee targets. For future years, Operations Engineering is forecasting a necessary increase in employees to address new and existing compliance requirements as detailed in Section 5.3.10.4 and to respond to anticipated capital program increases related to the LTSP. The employee increases related to proposed increases in capital spending will predominantly occur within the Project

Management Office and will be managed to ensure appropriate resource response to capital project levels and timelines.

5.3.10.3 Operations Engineering 2010 and 2011 Review – Mainland and Vancouver Island

Operations Engineering requested funding for compliance and employee related matters in the 2010-2011 RRA. We believe that we are continuing to successfully deliver against all of those established targets and regulatory initiatives. Our specific delivery on our funding requests are as follows:

- We applied additional funding to the processing of BCOneCall tickets and consistently met the 2 day turnaround requirement of the BCSA for the ticket volumes of 2010 and 2011;
- The funds approved for compliance with the requirements of CSA Z662 Clauses 10.2.1 and Clause 10.2.2 have been applied accordingly and we are now in compliance with these code requirements;
- We spent funds approved through the 2010-2011 RRA on implementing a formal training and competency model for technical staff performing elements of our Asset Integrity Management Programs;
- With respect to gas system asset records and their management, we migrated critical cathodic protection data from our contractor into our systems and we added half of a full time support staff to coordinate the management of our gas system asset records;
- The Corrosion group completed a one-time additional CP survey. As such, the affected cathodic protection records are now located in our Corrosion Data Management System;
- We continue to be able to operate our rectifiers for the cathodic protection of the steel assets because of the funding provided;
- We met our increased vegetation management cost, ROW fees and public awareness program cost;
- We continued to be able to fund our odorant requirements;
- The funds approved for demographics allowed and continues to allow us to successfully and proactively transfer knowledge and skill from our retiring workforce; and
- We successfully funded the Front End Engineering and Design (“FEED”) of many capital projects from the money that was reclassified to O&M due to accounting changes.

5.3.10.4 Operations Engineering 2012 and 2013 Forecast - Mainland

The pipeline regulatory landscape is constantly evolving based on new information, external events, and objectives and directives of the BCUC, the OGC and others having jurisdiction. Operations Engineering will require additional funding in 2012 and 2013 to continue to maintain regulatory compliance and to address recent and anticipated changes in regulatory requirements. Table 5.3-49 sets out approved, actual, projected, and forecast O&M costs for Operations Engineering. These costs are reviewed below.

Table 5.3-49: Prudent and Reasonable Increase to Meet Compliance Challenges

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	13,288	(122)	326	533	-	(190)	242	788	14,076
2013	14,076	-	378	44	-	-	135	557	14,633

CODES AND REGULATIONS

Operations Engineering requires funding to maintain regulatory compliance and also to comply with new regulatory requirements. Each of these requirements is discussed in detail below, with reference to the applicable regulation.

ONGOING REGULATORY COMPLIANCE REQUIREMENTS

On-going regulatory compliance is a key cost driver for the Operations Engineering group. We require additional funding of $208 thousand in 2012 and $94 thousand in 2013 to maintain regulatory compliance related to increased BCOneCall ticket handling costs, increased gas sampling requirements, changes to cathodic protection testing required pursuant to Asset Integrity Management Plan ("AIMP") CSA Z662 Annex N and system capacity network planning requirements.

NEW COMPLIANCE - CSA S250

The soon to be published CSA S250 Mapping Standard for Underground Utilities is the first new driver of funding requirements. This new standard "will specify the mapping requirements for the recording and depiction of underground utility infrastructure, and related appurtenances at or near grade and will apply to proposed existing, abandoned in-place, retired, or reserved for future use, underground utility infrastructure"[91]. FEI participated in the second and final reading of the new standard and will require incremental funding to be able to comply with the standard when it is published (anticipated to be some time in 2011). We need an incremental $222 thousand in 2012 to fully fund a GIS Drafter Leader and required land base mapping, drafting

[91] CSA S250 Standard Mapping of Underground Utility Infrastructure http://www.ogra.org/lib/db2file.asp?fileid=24694

interface and drawing management activities in compliance with this new standard. Subsequently, we will reduce the 2013 budget by $50 thousand that is associated with a one time consultant related ask in 2012. The publication of CSA S250 is imminent and we need funding to bring our GIS system in compliance.

NEW COMPLIANCE - OIL AND GAS ACTIVITIES ACT

The new B.C. Oil and Gas Activities Act ("OGAA") that replaced the B.C. Pipeline Act and became law in October 2010 is the second new driver of funding requirements. As stated on the Oil and Gas Commission website, "Regulations were added and strengthened in areas of compliance, consultation, reclamation, reviews and conservation."[92] New regulations made under OGAA require pipeline companies to perform extensive consultations with communities, landowners, First Nations, environmental groups and industry, reflecting the needs of the people, environment, industry and government. In response to the new and expanded requirements of the OGAA, we need an additional $103 thousand in 2012 to be maintained in 2013 to fully fund an employee for the OGAA Project Coordinator position. Approval of this funding request will allow us to be in compliance with this new requirement of OGAA.

DEMOGRAPHICS

Operations Engineering successfully addressed the demographic challenges faced during the 2010 and 2011 period. The $190 thousand reduction for demographics in Table 5.3-49 above represents the reduction of transitional headcount that was in the budget to address our 2011 demographic challenge.

SERVICE STANDARDS AND RELIABILITY

Operations Engineering needs to increase its resource capacity in order to deliver on the sustainment plan described in Section 6.2. We need an additional $242 thousand in 2012 and $135 thousand in 2013 to provide the required administrative and support resources for the LTSP and programs identified in the plan. Failure to approve this funding request will hinder our ability to execute the sustainment plan and to support the strategic direction of the FEU.

5.3.10.5 Operations Engineering 2012 and 2013 Forecast - Vancouver Island

The Operations Engineering O&M on Vancouver Island consists primarily of property services, corrosion inspections and engineering support services. There are no forecast changes in 2012 or 2013, other than the HST savings for 2012 as allocated to the Operations Engineering group. The 2012 and 2013 Operations Engineering O&M for Vancouver Island is shown in Table 5.3-50 below.

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92 Oil & Gas Activities Act – Regulating Change, Community www.bcogc.ca/OGAA/

Table 5.3-50: Vancouver Island Operations Engineering O&M Stable for the Forecast Period

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	679	(2)	-	-	-	-	-	(2)	677
2013	677	-	-	-	-	-	-	-	677

5.3.10.6 Operations Engineering Summary

Operations Engineering has implemented and maintained compliance in the areas of Project Management, Geographic Information Systems, System Integrity, Corrosion, Property Services, System Planning, the Gas Lab, and Location Records, and will continue to manage and execute all requirements in 2012 and 2013.

5.3.11 OPERATIONS SUPPORT

5.3.11.1 Operations Support Departmental Overview

Distributed among several communities within British Columbia including Burnaby, Surrey and Penticton, Operations Support is comprised of Measurement Services, Instrument Control Systems and Data Acquisition, Supply Chain Management and Mechanical Services, and Procurement. These groups are staffed with highly skilled analysts, trades people and employees trained to offer meter asset management, technical analysis, field support and supply chain services as described below.

MEASUREMENT SERVICES

METER FLEET MANAGEMENT

Meter Fleet Management encompasses all activities related to maintaining the "health" of the meter fleet in a manner that is cost effective, reliable, and compliant with all federal regulations and public policy. It also includes meter services to third parties.

INSTRUMENT CONTROL SYSTEMS AND DATA ACQUISITION

INSTRUMENTATION AND DATA ACQUISITION

Instrumentation and Data Acquisition involves the maintenance of instrumentation, control and data acquisition systems throughout the Companies' pipeline network. Included are activities associated with daily data validation, editing and estimation on behalf of the commercial and industrial customers who purchase their natural gas through a commodity broker.

RADIO NETWORK MANAGEMENT

Radio Network Management refers to the management of all aspects of the mobile radio network deployed throughout British Columbia. Included are all activities relating to ownership of repeater towers which provide an additional source of third party revenue.

SUPPLY CHAIN MANAGEMENT AND MECHANICAL SERVICES

MECHANICAL SERVICES

Mechanical Services refers to the manufacture and repair of equipment and tools as required by the Operations Department.

SUPPLY CHAIN MANAGEMENT

Supply Chain Management involves all activities related to managing the flow of inventory materials, tools and equipment used throughout the Companies.

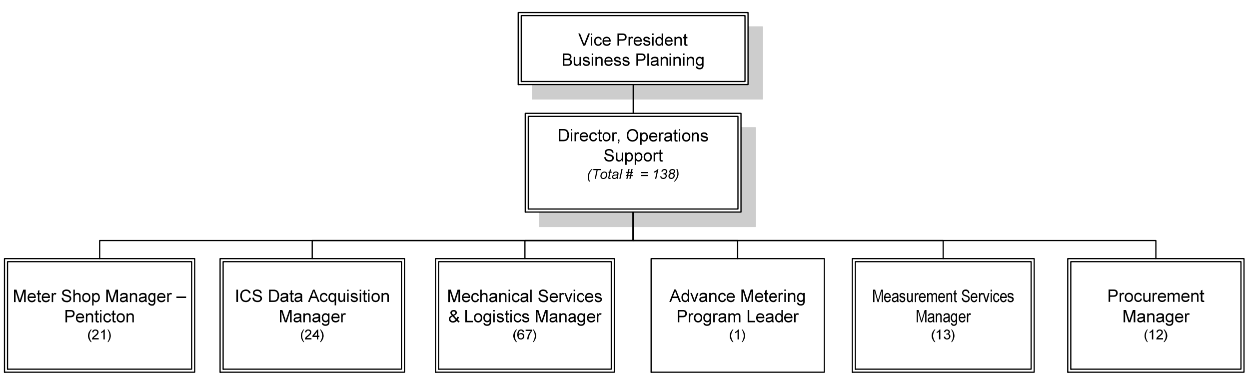
PROCUREMENT

The Procurement group is responsible for assisting departments across the Companies in acquiring a variety of materials and services. Procurement ensures the appropriate processes are followed and agreements are in place in acquiring materials and services. Procurement also assists with market research, risk management, tender evaluations and vendor management.

OPERATIONS SUPPORT ORGANIZATION CHART

The organizational chart for the Operations Support department is presented below.

Figure 5.3-7: Organization Chart for Operations Support



5.3.11.2 Operations Support O&M Expenditures and Employees

Codes and regulations combined with system reliability requirements form the foundation of many of Operations Support department expenditures. Table 5.3-51 sets out approved, actual, projected, and forecast O&M costs for Operations Support. These costs are reviewed later in this section.

Table 5.3-51: Operation Support O&M Requires Significant Increases in the Forecast Period

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 9,486	$ 9,715	$ 9,847	$ 9,847	$ 11,238	$ 11,802
Vancouver Island	$ -	$ -	$ -	$ -	$ -	$ -
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 9,486	$ 9,715	$ 9,847	$ 9,847	$ 11,238	$ 11,802

The cost of employees needed for the completion of Operations Support work activities are included in the O&M costs presented in Table 5.3-51. Note that in addition to the completion of O&M activities, Operations Support employees contribute to the delivery of capital projects as required. Employees consist of a combination of M&E, COPE, and IBEW resources. Table 5.3-52 provided below presents the approved, actual, projected, and forecast employees for Operations Support.

Table 5.3-52: Operations Support Shows Stable Staffing Levels

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	138	124	138	133	139	142
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	138	124	138	133	139	142

Capital/Deferral Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	52	48	50	50	50	50
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	52	48	50	50	50	50

O&M Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	86	76	88	83	89	92
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	86	76	88	83	89	92

An overview of the O&M and employee changes is provided in Sections 5.3.11.3 and 5.3.11.4 below.

For a discussion of capital expenditures please refer to Section 6.2.

5.3.11.3 Operations Support 2010 and 2011 Review - Mainland

2010 was a challenging year for Operations Support because of the large amount of infrastructure and maintenance work occurring throughout the Province creating increased demand for materials and services while at the same time we experienced an elevated rate of employee turnover resulting in an unsustainable number of vacancies.

Despite implementing a number of cost saving measures to defer spending where reasonable to do so, Operations Support still exceeded its O&M budget by $229 thousand or 2.4 percent. This additional spending on materials and services was required to ensure safety, asset reliability and compliance with public policy was maintained. Some of the drivers of this additional spending include both ongoing and one time spending as listed below.

- Increases in maintenance activities incurred more spending on related materials and replacement parts;
- Increases beyond the inflation rate in the price of these replacement parts;
- Additional inventory of maintenance materials to outfit new field employees with standard quantities; and
- Increase in transportation costs so materials were provided at the required time and location throughout the Province.

Also throughout 2010, Operations Support experienced a large number of employee retirements plus a significant number of employees that transferred to positions within other departments resulting in a considerable recruiting effort within the department. This higher than normal level of employee movement, combined with the unique skill sets required to fill the positions left vacant, resulted in an average of 10 O&M vacancies as shown in Table 5.3-52.

In 2011, Operations Support's activity level is projected to increase slightly, while both the one time expenditures and the rate of employee turnover is expected to decline. Operations Support anticipates meeting the approved 2011 O&M budget. In addition, Operations Support will continue to actively recruit for vacancies and expects to fill them throughout 2011 and early 2012 in order to ensure all O&M activities are completed and the Company's capital program is adequately supported.

5.3.11.4 Operations Support 2012 and 2013 Forecast - Mainland

Operations Support's O&M costs are driven by several critical activities conducted in support of the Companies' operating activities. These activities include management of the Companies' meter fleet, maintenance of instrumentation and communication equipment, and supply chain and procurement services. Therefore, as demand for these services is projected to increase due to growth within the business and changes in public policy, a corresponding increase in Operations Support O&M funding is required to continue providing these services in a safe, reliable and cost effective manner.

Table 5.3-53 below shows the increase in Operations Support's O&M budget for 2012 and 2013. Each of the main drivers is described further below.

Table 5.3-53: Increased Funding Driven by Support Activities for Operations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	9,847	(91)	675	352	67	-	387	1,391	11,238
2013	11,238	-	252	65	10	-	237	564	11,802

CODES AND REGULATIONS

Operations Support has three incremental funding requirements for 2012. These are in the areas of communication systems, gas detectors, and maintenance on emergency response equipment. Each of these items is discussed below.

Operations Support requires $170 thousand in O&M funds in 2012 to mitigate the risk of losing the use of the Company's communication systems that are critical to a coordinated emergency response. The FEU owns and operates a series of radio towers located throughout the Province. These towers are used by voice and data communication systems that are critical to the daily and emergency operations of the FEU. In the summer of 2009, one of the Company's radio towers was at risk of being damaged from a nearby forest fire. A subsequent review of the various radio tower sites showed that these assets require a program of vegetation management in the surrounding area to protect these sites from potential damage. In addition, structural inspections and maintenance are now required because of the age of our towers. Inspections are mandated by regulation CSA-S37-2006 and will ensure the radio towers are operated in a safe and reliable manner.

Operations Support requires an additional $105 thousand in O&M funds in 2012 to maintain our fleet of gas detectors due to the introduction of new units that are capable of monitoring methane and other dangerous gases. This funding requirement is critical to the ongoing maintenance of these units as they are the first line of defence for our customers and employees working in an environment where dangerous gases can be present. The need for these gas detectors is mandated in Worksafe BC's Occupational Health and Safety Regulation Section 5.48 and in CSA Z662 10.3.7.1

Operations Support requires $77 thousand in O&M funds in 2012 to maintain critical emergency response equipment. This equipment has reached the age that manufacturers recommend to start performing preventative maintenance functions. The availability of emergency equipment is stipulated in CSA Z662 10.3.2.5. FEI will be at risk of its critical emergency equipment not being available or failing when it is most needed if this maintenance is not performed as recommended by the manufacturer.

In 2014, Measurement Canada, the federal agency that regulates FEU's meter fleet, is legislating sampling plan SS06 which is a more rigorous standard on meter sampling, testing and accuracy tolerances than the existing standard. In particular, SS06 will result in a 50 percent increase in the number of meter samples. As such, in 2013 Operations Support requires $65 thousand to meet Measurement Canada's requirements for testing and reporting of meters in order to avoid potentially costly fines. To ensure FEU's meter fleet meets these requirements and avoids costly fines two additional labour resources will be required in the second half of 2013. These resources will be trained on measurement operations and be involved with additional meter handling and testing so our meter fleet will be in compliance with Measurement Canada's regulations by January 1, 2014.

CUSTOMER AND STAKEHOLDER EXPECTATIONS

FEI offers automated meter reading ("AMR") service to its existing 2,700 commercial and industrial customers that fall within rate schedules 5, 7, 22, 23, 25, and 27. The most recent AMR units use cellular networks as the communication medium instead of the previously used landlines, and FEI has negotiated an agreement with a network provider for wireless services to support these units. Given the success of this technology it is prudent to continue deploying this wireless AMR technology to customers in these rate classes. Funding of $40 thousand in 2012 and additional $20 thousand in 2013 will allow FEI to meet its obligation of providing daily customer consumption information to the respective gas marketers who require this information to optimize their daily gas purchasing decisions.

One additional head count is required part way through 2012 at an incremental cost of $52 thousand to support growth in the business, including new biomethane and NGV programs. The biomethane program is described in Appendix J and NGV program is described in Appendix I.

Offsetting these pressures, Operations Support is expecting an increase in third party revenue activities by $25 thousand in 2012 and an additional $10 thousand in 2013.

SERVICE STANDARDS AND RELIABILITY

Beginning in 2011, FEU began recalling electronic meters installed in vertical subdivisions to be tested for accuracy in accordance with Measurement Canada regulations. At the same time, these meters are scheduled to have their batteries replaced to ensure reliable operation after redeployment to the field. This level of maintenance will continue through 2012 and 2013 and beyond as the next group of installed electronic meters become due for recall. Also in 2010 one of the vendors supplying rotary meters currently deployed in FEU's fleet began offering lithium battery packs to energize the associated micro-correctors in place of the alkaline batteries previously used. This change has resulted in an incremental cost for each meter maintained in the meter shop. The total increase in O&M funding to support the battery replacements in 2012 is $181 thousand and in 2013 an additional $71 thousand. Secondly, FEI will be purchasing additional parts for meter sets to continue delivering gas safely to customers at an additional cost of $149 thousand in 2012. Funding for these materials will allow the Company to extend the life of these assets deferring the cost of replacement.

To cover inflation related to parts and materials required to support Operations Support's responsibilities, $57 thousand is requested in 2012 and an additional $59 thousand is requested in 2013.

Finally, one additional headcount will be required in 2013 to support the LTSP projects at an incremental cost of $107 thousand.

5.3.11.5 Operations Support Summary

Operations Support provides critical asset management, emergency response and system maintenance service to FEU operations. The O&M required to provide these services is increasing because of the increase in activities and the rising cost of parts, and is required in order to continue to provide the level of service required to ensure the safe, reliable and cost effective operations.

5.3.12 FACILITIES

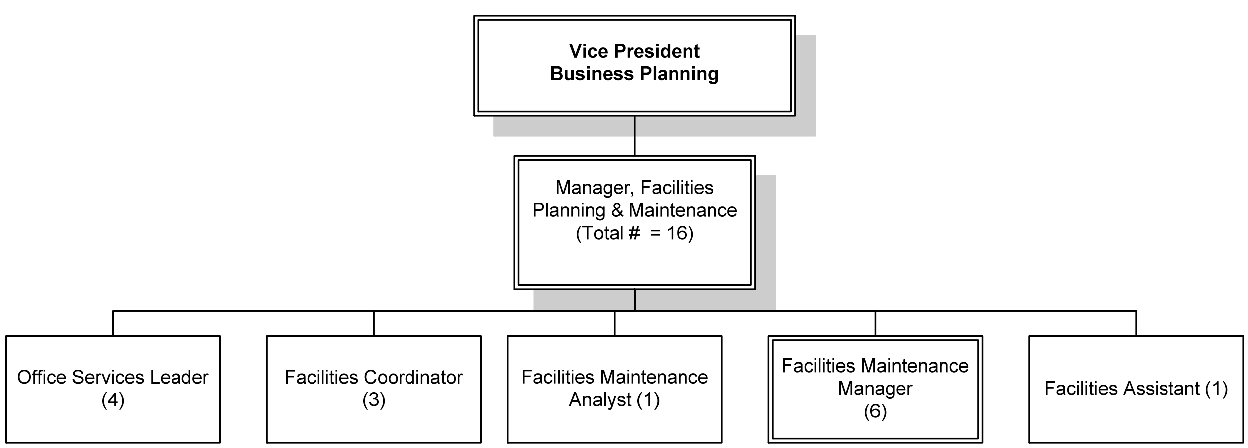
5.3.12.1 Facilities Departmental Overview

The Facilities department is a centralized service group that is responsible for operating and maintaining all non-gas facilities. The services range from building asset operation and maintenance, physical security, space planning, office furniture and equipment, mailroom and reception services. The department ensures that the FEU Companies and their employees have a suitable work environment with safe and efficient buildings and workspaces.

FACILITIES ORGANIZATION CHART

The organization chart for the Facilities department is presented below.

Figure 5.3-8: Organization Chart for Facilities



5.3.12.2 Facilities O&M Expenditures and Employees

Facilities is responsible for a wide range of services, including:

- Cyclical maintenance - This is preventative maintenance service to keep facility assets in good condition, improving equipment utilization and reliability, and ensuring the health, safety and welfare of our employees. As this maintenance is cyclical, the spending pattern associated with these tasks varies based on manufacturer recommendations, best practices and code compliance. Maintenance levels will fluctuate over multiple years, with a corresponding impact on the forecast expenditures;
- Lease Contracts – The FEU Companies hold leases for 26 of their locations. Lease contracts have stepped rate increases, renewals and expiries that affect the required operating costs for the various facilities. Lease contracts demand market rates for the specific lease area;
- Lease Revenue – Facilities acts as the Landlord to tenants at 8 facilities. Lease revenue, similar to lease contracts, have stepped rate increases, renewals and expiries that affect the required operating costs for the various facilities;
- Service Contracts – Contracts for various services are competitively tendered and negotiated over a fixed term. Contract increases can be stepped within the contract term or require renegotiation;
- Operating Costs for utility services – electricity rates are periodically reset; and
- Administrative General – These costs vary with changes to headcount at our facilities, and requirements for consulting costs to ensure subject matter expertise on specific facilities-related concerns. Headcount increases stress the available space and force increases to off-site record storage requirements, additional stationary and janitorial supplies and increases in electricity requirements.

Table 5.3-54 sets out approved, actual, projected, and forecast O&M costs for Facilities. These costs are reviewed later in this section.

Table 5.3-54: Facilities O&M Required to Meet Cyclical Maintenance and Contractual Inflation

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 6,417	$ 6,681	$ 6,201	$ 6,201	$ 6,430	$ 6,353
Vancouver Island	$ 1,521	$ 1,460	$ 1,618	$ 1,618	$ 1,463	$ 539
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 7,938	$ 8,140	$ 7,819	$ 7,819	$ 7,893	$ 6,892

The cost of M&E and COPE employees in the Facilities department are included in the O&M costs that are set out in Table 5.3-54 above. Table 5.3-55 that follows sets out approved, actual, projected, and forecast employees for Facilities.

Table 5.3-55: Employees Supporting Facilities Operations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	17	14	16	17	18	18
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	17	14	16	17	18	18

An overview of the O&M and employee changes is provided in Sections 5.3.12.3 through 5.3.12.6 below.

5.3.12.3 Facilities 2010 and 2011 Review - Mainland

The Facilities group continues to provide efficient and effective asset management practices and support services to all FEU Companies. In 2010 and 2011, Facilities operated and maintained buildings to ensure equipment utilization and reliability and provided a suitable and safe workplace for our employees. In 2010, Facilities was challenged with unplanned work which has been necessary to complete.

In 2010, Facilities actual costs were $264 thousand above the approved budget. The reason for the increase in expenditure is as follows:

- Flooding occurred at two of our facilities as a result of heavy rainfall which caused water damage to the interior of the Cranbrook and Trail Regional offices. Costs of repairs were $65 thousand.
- Our buildings are increasing in age and increased maintenance and repairs are required to the roofs to prevent roof leaks and extend the life cycle of the assets. As a result of roof condition assessments, Facilities expensed an additional $81 thousand for roof repairs.
- The majority of regional facilities and operations centres have no available workstations. Increased headcount above what had been forecast and incorporated into the Facilities budget resulted in additional reconfiguration, densification and restacking of the facilities. The additional cost to Facilities was $115 thousand.

Facilities employee headcount for 2010 was not attained as a result of competency review and job description re-writes for the Maintenance roles which required a delay in hiring. During the year, vacancies were back filled by contractor services to ensure operations and maintenance were not impacted. Posting of the revised job descriptions was completed in 2010 and the positions are expected to be filled in 2011. In addition, Facilities carries one IBEW employee to cover vacation relief. The vacation relief was filled by contractor services in 2010 as the Company could not release qualified resources from other areas of the organization. In 2011, an additional headcount will be added in the 4th quarter to begin the extensive training requirements to ensure the individual is performing at 100 percent by 2012. As this position is funded 50 percent capital and 50 percent O&M it will have a minimal impact on the 2011 budget.

The decrease from 2010 to 2011 approved is due to the cyclical nature of some of the reconfiguration and maintenance work completed in 2010.

5.3.12.4 Facilities 2010 and 2011 Review - Vancouver Island

Vancouver Island was favourable to budget by $61 thousand in 2010. This was a result of reduced electrical and natural gas charges from lower consumption, and consulting costs. As these variances are not expected to carry forward into this year, Facilities projects it will be on budget for 2011.

5.3.12.5 Facilities 2012 and 2013 Forecast - Mainland

Changes in expenditures in Facilities in 2012 and 2013 are to meet Service Standards and Reliability, as Facilities ensures delivery of a suitable work environment with safe and efficient buildings and workspaces.

As shown in Table 5.3-56 below, Facilities expenses increase for the Mainland area by $228 thousand in 2012, followed by a decrease of $77 thousand in 2013.

Table 5.3-56: Changes in Mainland Facilities Costs Driven by Service Standards and Reliability

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	6,201	(57)	24	-	-	-	262	228	6,430
2013	6,430	-	62	-	-	-	(139)	(77)	6,353

SERVICE STANDARDS AND RELIABILITY

The 2012 Service Standards and Reliability increases are driven by the following:

- Cyclical Building Maintenance increase of $205 thousand to complete projects including electrical vault inspections and interior painting at our Burnaby Stores and Shops location;
- Service Contract increases of $130 thousand for HVAC, janitorial, snow removal and security contracts;
- Labour increase of $87 thousand for addition of 1 M&E headcount as a result of continual increase in workload due to more buildings that are aging and have greater maintenance requirements and more employees who require space and services;
- Operating Cost increase of $81 thousand as a result of higher electricity rates;
- Lease Contract increases of $60 thousand;
- Consulting Fee increase of $56 thousand to complete an energy study for one facility which will provide recommended improvements to reduce energy consumption and GHG emissions, and a building envelope condition assessment for one site which provides condition of building envelope, and addresses any areas of concern with options and recommendations and expected remaining life;
- Remaining increases of $68 thousand for off-site record storage, office supplies, and other miscellaneous costs; offset by
- Lease revenue increases of $425 thousand including tenant contract stepped rate increase at the Kelowna Regional Office, tenant expiry and removal of one lease at the Kamloops Regional Office, and a new tenant contract at the Tilbury location.

For 2013, the Services Standards and Reliability category is expected to decrease by $139 thousand as a result of a reduction in cyclical building maintenance and expiry of the FortisBC Holdings Centre head lease, partly offset by continuing energy cost increases.

5.3.12.6 Facilities 2012 and 2013 Forecast - Vancouver Island

Vancouver Island Facilities expenses are forecast to decrease by $155 thousand in 2012 and a further $924 thousand in 2013, mainly due to the expiry of the Langford Muster and Garbally leases, and the resulting relocation of the Victoria Regional Operations Centre to an owned facility, as approved by Commission Order No. C-6-11. These changes are shown in Table 5.3-57 below.

Table 5.3-57: Facilities O&M Savings as a Result of New Victoria Regional Operations Centre

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	1,618	(5)	-	-	-	-	(150)	(155)	1,463
2013	1,463	-	-	-	-	-	(924)	(924)	539

5.3.12.7 Facilities Summary

The forecast changes in costs continue to be driven by contractual inflation and required service levels for operating and maintaining building assets. The changes are required to ensure Facilities can continue to deliver a suitable work environment with safe and efficient building and workspaces.

5.3.13 HUMAN RESOURCES

5.3.13.1 Human Resources Departmental Overview

The overall goal of the Human Resources function is to ensure that FEU's workforce, now and into the future, has the level of skill and capacity to achieve the Companies' business goals and objectives. The Human Resources department performs and provides different services to support management of FEU's workforce to ensure effective and efficient alignment with FEU's business plans. The following sections provide an overview of the activities and responsibilities within each of the four functional areas in the Human Resources department.

CORPORATE HUMAN RESOURCES

Ensures HR direction and people practices are aligned with departmental and corporate goals and objectives. Areas of responsibility include HR business planning, HR policy development and review, HR governance and reporting, regulatory requirements and corporate HR initiatives.

EMPLOYEE SERVICES

Oversees the design and delivery of the Total Rewards framework that supports the needs of the business by ensuring FEU is able to attract, retain and motivate the type of employees needed to reinforce the desired corporate culture and leadership style. Areas of responsibility include compensation, payroll and time administration, HR Information Systems and master data, and HR metrics, surveys and reporting.

EMPLOYEE RELATIONS

Provides direction and delivery of labour relations and advisory services in an effort to maintain and foster a productive and cooperative employee relations climate. Areas of responsibility include employee and labour relations, HR advisory services, disability and attendance management, collective agreement administration and collective bargaining and contract negotiations.

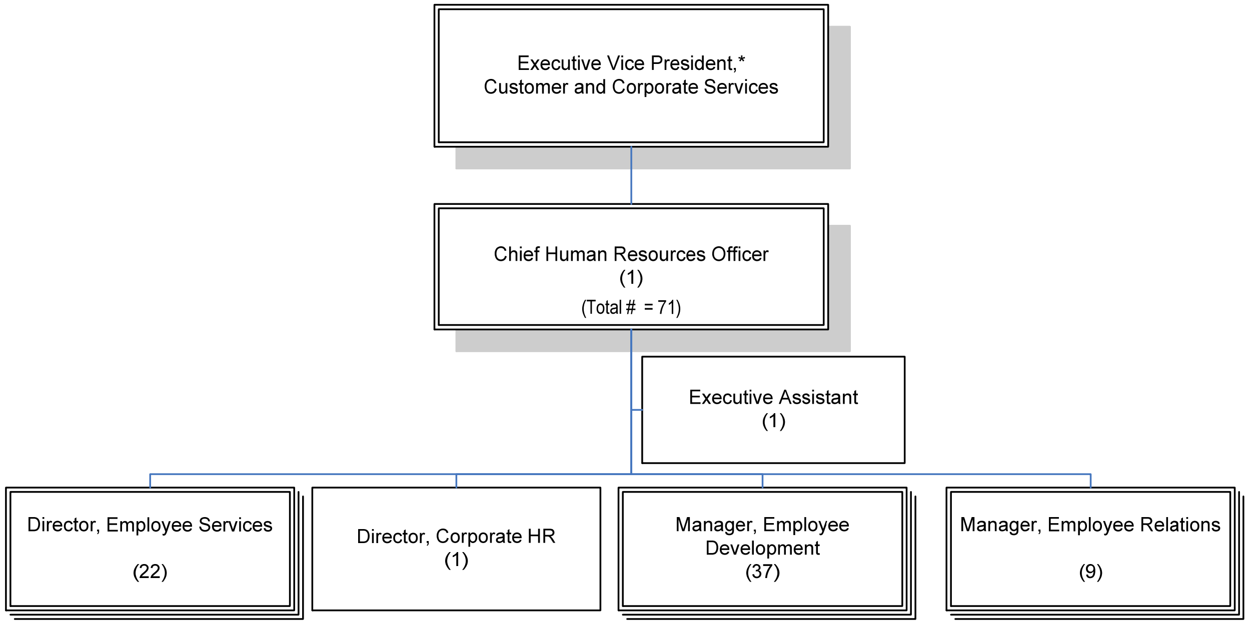
RECRUITING AND EMPLOYEE DEVELOPMENT

Ensures recruiting and selection processes meet business needs and operational requirements. Partners with the business to design and deliver employee training, including management and leadership development programs. Areas of responsibility include recruiting and relief services, development and delivery of trades training and in-house apprenticeship programs, learning content management, management training and leadership development, competency management and administration and training records.

HUMAN RESOURCES ORGANIZATION CHART

The organizational chart for the Human Resources department is presented below.

Figure 5.3-9: Organization Chart for Human Resources Department



The structure of the Human Resources department allows the Companies to efficiently respond to evolving workforce needs required to support achievement of the Companies' objectives and business plans. FEU will continue to place a high priority on all Human Resources activities and talent management needs in order to meet our objectives of retaining, attracting and motivating employees in order to meet customer needs and achieve desired business results.

5.3.13.2 Human Resources O&M Expenditures and Employees

Table 5.3-58 sets out approved, actual, projected, and forecast O&M costs for Human Resources. These costs are reviewed later in this section.

Table 5.3-58: HR O&M Increasing in Response to Evolving Needs

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 8,052	$ 8,335	$ 8,280	$ 8,280	$ 8,966	$ 9,382
Vancouver Island	$ -	$ -	$ -	$ -	$ -	$ -
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 8,052	$ 8,335	$ 8,280	$ 8,280	$ 8,966	$ 9,382

The cost of M&E and COPE employees needed for the execution of the Human Resources function are included in the O&M costs that are set out in Table 5.3-58 above. Table 5.3-59 that follows sets out approved, actual, projected, and forecast employees for Human Resources.

Table 5.3-59: No Increase in Employees Between 2011 and 2013

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	71	116	72	70	71	72
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	71	116	72	70	71	72

An overview of the O&M and employee changes is provided in Sections 5.3.13.3 and 5.3.13.4 below.

5.3.13.3 Human Resources 2010 and 2011 Review - Mainland

In 2010, FEU experienced a 130 percent increase in the number of employees hired over 2009. This pace is expected to continue in 2011 in addition to the more than 300 new hires which will be required for Customer Service and the new Customer Contact Centres in Burnaby and Prince George. Some departments, particularly the Distribution and Transmission groups within Operations, will experience higher than normal hiring activity in order to replace retiring employees. As the Companies address staffing needs, there will be additional challenges to meet the demand for leadership development and competency based training.

Table 5.3-58 above shows that in 2010, HR exceeded its approved budget by $283 thousand. These funds were used to support the design and delivery of a Leadership Development program to raise awareness and understanding of the core leadership competencies across the Companies.

Table 5.3-59 above reflects an increase of 1 employee between 2010 and 2011 approved, which is the Instructional Designer to support the increased demand for new training. The apparent spike in 2010 Actual employees is due to the fact that the actual employee counts include approximately 45 temporary Relief Services personnel who are hired and managed by the Human Resources Department (and included in HR’s Actual employees), but whose services are charged out to various operating departments that require temporary relief to fill vacant positions. HR does not budget or forecast requirements for Relief Services personnel as the need is determined by operational requirements within the various departments. The reduction of 2 employees approved vs. projected for 2011 results from the reallocation of full-time instructor resources to peer trainers. The instructor headcount has been reduced, but the costs are still incurred in the HR department as peer trainers charge their labour and expenses to the Training Department.

The current demographic profile presents new challenges with respect to training and employee development. These challenges relate not only to the anticipated increased volume of hiring activity, but also the changing skill-sets and competencies required for existing employees as they move into new positions. A total of 270 IBEW employees have been hired since 2007 (new hires, re-hires, and changes in affiliation), each requiring various levels of training. Of those, 108 were hired between Jan. 1, 2010 and Feb. 28, 2011. Structured, competency based training was formally implemented for specific field employees in 2010 to ensure that the Companies were able to demonstrate compliance with new regulatory requirements. In 2011, projected training delivery costs required to support the increased volume of training for field employees is forecast to exceed budget. This pressure will be offset in 2011 by prioritizing formal training based on available funding; however, this is not a sustainable solution in the longer term. The Companies have also moved to a combination of Peer Trainers and full-time Instructors. The use of Peer Trainers allows employees to be trained closer to their work locations reducing travel time and associated expenses.

5.3.13.4 Human Resources 2012 and 2013 Forecast - Mainland

In order to be able to continue to ensure that FEU's workforce has the level of skill and capacity to achieve the Companies' business goals and objectives, Human Resources requires approximately $687 thousand in incremental O&M cost for 2012 and a further $416 thousand in incremental O&M costs for 2013. A discussion of these cost increases by cost driver follows.

Table 5.3-60: Incremental Human Resources O&M Requirements

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	8,280	(14)	265	59	-	313	65	687	8,966
2013	8,966	-	265	-	-	-	151	416	9,382

CODES AND REGULATIONS

Additional funding in the amount of $59 thousand is required in 2012 to satisfy all of the current requirements set out in CSA Z662 Annex "N" and ensure that the management of competencies is consistent, efficient and sustainable. This additional funding will ensure that governance functions required in the Competency Management Program are met and that data entry and reporting are completed in a timely manner. The Competency Management Program supports employees across the Company and is one of the fundamental building blocks for our talent management processes.

DEMOGRAPHICS

As discussed above, the current demographic profile presents new challenges with respect to training and employee development. Additional O&M in the amount of $225 thousand is required in 2012 to accommodate increased levels of training and related expenses in order to meet the demands of the business. To be more efficient and effective in training delivery, FEU is pursuing a blended model for learning that consists of instructor-led learning, computer based learning (e-learning) and informal learning (i.e. coaching, mentoring, self study, peer training, on the job training), supported by a competency management framework that ensures requirements are defined, and training is delivered when required. E-learning is a cost effective method of providing training to large groups of employees across the Province. The demand for e-learning is continuing to grow, and on-going development and delivery of e-learning requires dedicated technical support to sustain these learning assets.

In 2010, $100 thousand was approved for the development of e-learning. A further $59 thousand is required in 2012 to ensure that the deployment of e-learning courses is consistent, efficient and sustainable. This funding will also ensure that employees engaged in e-learning are supported when they encounter system or technical difficulties. To ensure the continued acceptance of this technology, the Training Department requires specialized support to ensure reliable access for e-learning across the Companies.

Managers across the companies are looking for better tools to assist them in analyzing, planning and managing their workforce. The Human Resources Information System (“HRIS”) roadmap (see Service Standards and Reliability below) includes plans to leverage additional functionality to support workforce planning that will attract additional O&M of $29 thousand in 2012

This funding will provide a stable base level of resources to develop and sustain training delivery and provide related tools for workforce planning.

SERVICE STANDARDS AND RELIABILITY

Beginning in 2010, HR began defining technical requirements for the department which were documented in an HRIS roadmap representing a coordinated, long term HR IT strategy that includes enhancements to existing systems. The following HRIS initiatives have been identified as highest priority and require additional O&M funding for IT support and sustainment in the forecast period. These initiatives will help streamline key business processes, provide for more efficient use of resources and give managers direct access to critical employee information they need to manage day-to-day operational requirements as well as develop short and long-term workforce plans.

First, is the purchase of additional SAP licenses, servers and related maintenance at a cost of $29 thousand in 2012. This is needed to support enhancements to HRIS that will improve the administration of processes related to annual salary planning and review as well as incentive pay calculations.

Second, one additional resource in the IT HR group in 2013 to support the implementation and sustainment of Employee Self Serve and Manager Self Serve ("ESS/MSS") at a cost of $109 thousand in 2013. ESS/MSS allows the automation of time entry, salary administration and compensation management, and workforce planning, all in SAP.

The remaining amounts of $36 thousand in 2012 and $42 thousand in 2013 are included to cover all non-labour inflation.

The immediate driver for automated time entry is the addition of approximately 300 employees in the Customer Care organization. Work is currently underway to have automated time entry available for the Customer Care organization at go-live in January 2012, followed by implementation across the remainder of the FEU in 2012 and 2013.

Once ESS/MSS has been fully operationalized across the organization (estimated in early 2014) operational efficiencies will be realized that will result in reduced requirements for resources in salary and time administration and reporting.

5.3.13.5 Human Resources Summary

The overall goal of the Human Resources function is to ensure that FEU's workforce, now and into the future, is of a quality and quantity to enable the achievement of FEU's business goals and objectives. FEU is entering a critical stage in a labour market that is challenged on two fronts, by an aging workforce, and a limited supply of younger, skilled workers graduating from trades and technology programs. In order to remain competitive and continue to grow its business, FEU needs to strengthen the foundation of its end to end talent management systems and processes. This need lies at the heart of the long-term Human Resources vision to "Retain, attract, develop and motivate the right people to achieve desired business results".

5.3.14 ENVIRONMENT, HEALTH & SAFETY

5.3.14.1 EH&S Departmental Overview

The Environmental, Health and Safety ("EH&S") group is made up of the following areas:

- Environmental Affairs, which manages environmental risks associated with operational activities and the fulfilment of compliance requirements with all applicable environmental regulation;
- Occupational Health and Safety, which manages employee safety risk as aligned with the maintenance of compliance with WorkSafeBC regulation;

- Public Safety Awareness, which involves the development of plans and strategies around the education of customers, first responders, and the general public around the properties of natural gas, about the steps to be taken in emergent situations, and about the processes to be followed prior to conducting any ground disturbance or excavation. Research conducted in the department tracks the overall efficacy of the safety communications plan, and allows for targeted messaging throughout the Province that can be adjusted based on customer responses to the annual survey or to the more frequent ad tracking that is conducted. The budget for the execution of the safety awareness communications plan is in the ES&ER group where the communication strategies are implemented;

- Emergency Preparedness, which involves the management of emergency response system compliance with all applicable legislation. An exercise program is conducted in concert with provincial emergency program inputs, in order to maintain operational readiness;

- Business Continuity Planning, a key component of the FEU Corporate Emergency Plan, which is comprised of inter-departmental processes that will serve to ensure timely operational response to our customers and the resumption of core business function if the current operational platforms are unavailable for use; and

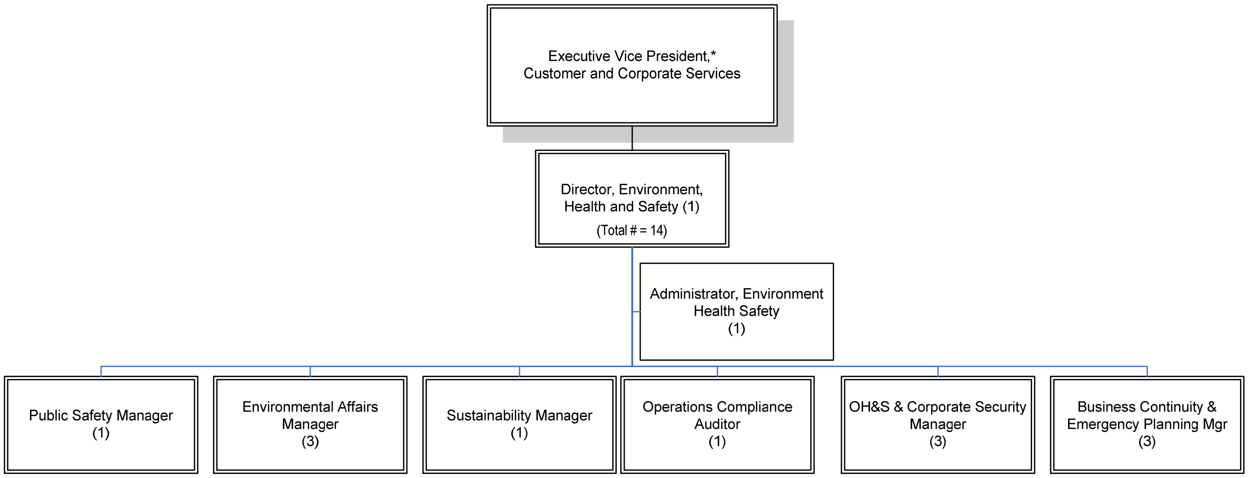
- Corporate Security, which manages corporate security risks.

The programs and activities noted strengthen the management systems that support each of these areas, so as to fulfill regulatory requirements and to provide a suitable working environment for our employees, customers, and the general public. The FEU place a high priority on safe work practice, and on minimizing the operational impact of works conducted on the natural environment.

EH&S ORGANIZATION CHART

The organizational structure for the EH&S Department is presented below.

Figure 5.3-10: Organization Chart for Environment, Health & Safety



5.3.14.2 EH&S O&M Expenditures and Employees

Table 5.3-61 sets out approved, actual, projected, and forecast O&M costs for EH&S. These costs are reviewed later in this section.

Table 5.3-61: EH&S Funding to Meet Changing Regulations and Governance Requirements

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 2,482	$ 2,583	$ 2,615	$ 2,615	$ 2,893	$ 3,057
Vancouver Island	$ -	$ -	$ -	$ -	$ -	$ -
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 2,482	$ 2,583	$ 2,615	$ 2,615	$ 2,893	$ 3,057

The cost of M&E and COPE employees needed for the EH&S department are included in the O&M costs that are set out in Table 5.3-61 above. Table 5.3-62 that follows sets out approved, actual, projected, and forecast employees for EH&S.

Table 5.3-62: EH&S Staffing Levels Stable Through the Forecast Period

Total Employees						
Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	12	12	14	14	14	14
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	12	12	14	14	14	14

An overview of the O&M and employee changes is provided in Sections 5.3.14.3 and 5.3.14.4 below.

5.3.14.3 EH&S 2010 and 2011 Review - Mainland

Additional expenses in 2010 above the approved level occurred as a result of enhanced regulatory tracking and review as related to emerging greenhouse gas regulation. Also, additional public safety messaging was conducted in the key areas of appliance maintenance, excavation diligence, meter safety, and gas odour awareness. These increases were offset by delays in the hiring of new employees. These positions, the Business Continuity Manager and Public Safety Manager positions as described in the 2010-2011 RRA, have now been filled, and there will be an additional manager brought in during 2011 to support the new Greenhouse Gas ("GHG") regulatory reporting activities which will be finalized this year, as well as a headcount to support safety and/or emergency preparedness.

B.C. GHG reporting regulation was further defined for operators in the Province, for both the new Provincial requirements and for the 'One Window' Federal reporting. The different levels of government have strived to avoid duplicating the regulatory reporting burden on industry, with the result that FEI and FEVI will each be able to submit provincial and federal GHG reporting requirements in a single report (FEW does not meet the reporting threshold). The GHG reporting regulation sets out requirements for the reporting of GHG emissions from B.C. facilities emitting 10,000 tonnes or more of CO2e per year beginning on January 1, 2010. Those facilities with emissions of 25,000 tonnes or more are required to have emissions reports verified by a third party.

5.3.14.4 EH&S 2012 and 2013 Forecast - Mainland

EH&S requires $278 thousand in incremental O&M cost for 2012 and a further $164 thousand in incremental O&M costs for 2013. A discussion of these cost increases by cost driver follows.

Table 5.3-63: EH&S O&M Increases to Meet Standards and Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	2,615	(5)	76	50	36	-	121	278	2,893
2013	2,893	-	52	35	50	-	27	164	3,057

CODES AND REGULATIONS

To maintain compliance with Annex A of the CSA Z662 Pipeline Standard, an incremental $50 thousand is required starting in 2012 for the delivery of compliance related environmental training for Operations employees. Operations employees have been hired in a larger group, and will continue to be hired, requiring continued environmental training.

The Companies maintain an Environmental Management System ("EMS") that is compliant with the ISO 14001 EMS standard. The EMS provides guidance to the Company, its employees, and its contractors on compliance requirements as related to all applicable environmental laws, Company policies and industry codes of practice. As part of the ongoing review and development of the EMS, FEI will be implementing an enhanced waste management tracking system in 2013 at a cost of $35 thousand, such that hazardous wastes logged throughout the Company are archived in a central repository. Hazardous wastes will be managed throughout their entire lifecycle, that is, during generation, characterization, treatment, storage, transportation, and disposal. FEI must comply with facility-specific permits and registration requirements per the provincial Environmental Management Act ("EMA"), the Federal Canadian Environmental Protection Act ("CEPA") and the Transportation of Dangerous Goods Act ("TDGA") and their associated regulations.

CUSTOMER AND STAKEHOLDER EXPECTATIONS

In terms of business continuity, additional contingencies are required to ensure the maintenance of key business processes if an event was to occur that would significantly impact the Surrey Operations site and require the activation of the Disaster Recovery ("DR") site. FEI recognizes that improvements must be made if the Company is to be fully prepared to respond to business interruption, regardless of the event. Loss of access to applications and data for an extended period of time is a significant exposure of the organization that needs to be addressed. The majority of companies in the energy and utility industry maintain formal IT / disaster recovery plans; prudent alignment of emergency planning, business continuity and disaster recovery planning has been an industry focus. FEI will attain an expanded DR capacity as well as an alternate location (to Surrey) for first response employees to work from in the event of an impacting event. In 2012 and 2013, $36 thousand is required, in order to purchase licenses, wiring, and other equipment related to telephony; in 2013, a further $50 thousand is required for similar materials that will enable the data access expansion to the DR site. Alternate physical work locations in existing FEI offices in the Lower Mainland will be equipped to manage daily operational requirements outside of the Surrey Operations site. Phone applications will also be expanded to alternate locations, such that post incident system restoration efforts can proceed without significant delay.

SERVICE STANDARDS AND RELIABILITY

The majority of incremental costs in this category relate to contracted increases in licensing fees for IT systems that support the business requirements of the EH&S group.

5.3.14.5 EH&S Summary

The strong corporate governance structure at the FEU, in addition to well defined policies and procedures that are monitored for performance, continue to be important in continually achieving business priorities. The recent 'COR' certification ('Certificate of Recognition') by WorkSafeBC, involving an external audit of the Company's safety management system, is reflective of the commitment to the continued improvement of the FEI safety management system. Three of the current corporate scorecard measures continue to measure workplace health and safety - Recordable Injuries, Recordable Vehicle Accidents and Wellness. The FEU continue to strengthen and fortify all existing management systems, such that risks are prudently managed in accordance with all applicable regulatory requirements

The assurance of operational readiness continues. Joint awareness initiatives with the Provincial Emergency Program, municipal/community representatives, and First Responders continue as related to coordinated response strategies. FEU continues to educate the public about the risks associated with its natural gas and propane products.

5.3.15 FINANCE AND REGULATORY AFFAIRS

5.3.15.1 Finance and Regulatory Affairs Departmental Overview

The Finance and Regulatory Affairs departments are responsible for providing a range of financial and regulatory services to various departments throughout the Companies as described below.

FINANCE

The range of services provided by the Finance department include: maintenance, reporting and analysis of the financial results; financial forecasting and budgeting; administering accounts payable and accounts receivable functions; managerial reporting and other functions.

REGULATORY AFFAIRS

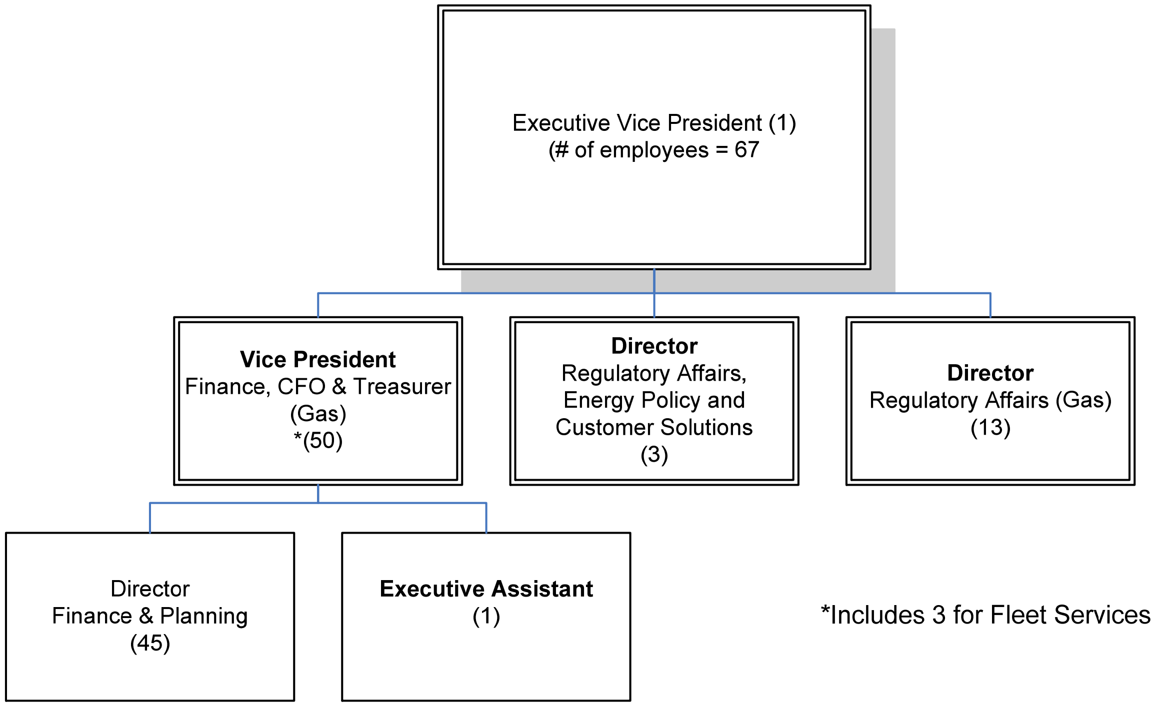
The Regulatory Affairs Department assists the operating groups, business units and Senior Management to achieve their goals in accordance with the UCA and requirements of the Commission.

The Regulatory Affairs Department provides support to the FortisBC Energy utilities by:

- Developing pro-active regulatory plans in support of current and prospective regulatory initiatives and issues;
- Assisting the operating groups with the regulatory process, regulatory and industry research, and analytical support for projects and initiatives;
- Developing rate design (rate pricing) structures that are in alignment with cost structures;
- Managing each utility gas tariff related to applications for changes and new initiatives and ensuring implementation of rate changes;
- Managing regulatory relationships with the Commission and stakeholders on behalf of the gas utility companies; and
- Managing the gas utility companies' compliance with Regulations, Orders, Directives and Decisions.

FINANCE AND REGULATORY AFFAIRS ORGANIZATION CHART

Figure 5.3-11: Organization Chart for Finance and Regulatory



5.3.15.2 Finance and Regulatory Affairs O&M Expenditures and Employees

In order to continue to successfully meet the requirements of our various stakeholders, the Finance and Regulatory Affairs department requires the forecast expenditures and headcount for the 2012 and 2013 test years as shown in Tables 5.3-64 and 5.3-65 below. The Companies believe these forecast expenditures are reasonable, and consistent with expenditure levels observed in recent years.

Table 5.3-64: Finance and Regulatory O&M Forecast to Meet Future Requirements

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 9,616	$ 9,343	$ 9,953	$ 9,953	$ 11,071	$ 11,399
Vancouver Island	$ 380	$ 381	$ 383	$ 383	$ 493	$ 493
Whistler	$ -	$ -	$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 9,997	$ 9,724	$ 10,336	$ 10,336	$ 11,564	$ 11,892

Table 5.3-65: Finance and Regulatory Employees to Meet Future Requirements

Total Employees						
Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	69	68	69	69	69	69
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	69	68	69	69	69	69

The number of employees is expected to remain unchanged during the forecast period. An overview of the O&M changes is provided in Sections 5.3.15.3 through 5.3.15.5 below.

5.3.15.3 Finance and Regulatory Affairs 2010 and 2011 Review – Mainland

During 2010 the Finance and Regulatory Affairs department spending was below the 2010 approved budget. Labour savings resulting from staff turnover and vacancies contributed to the lower spending for the FEU as per Table 5.3-65 above.

In 2011, as vacancies have been filled and the staffing levels in Finance and Regulatory Affairs normalize, the department is expected to meet its budget.

The 2010 Actuals and 2011 Projection O&M are in line with the approved amounts, with the exception of the labour challenges discussed above. The Finance and Regulatory department remains committed to providing the necessary support to the various departments within the FEU in order to achieve our overall organizational commitments.

5.3.15.4 Finance and Regulatory Affairs 2012 and 2013 Forecast – Mainland

Finance and Regulatory Affairs will require the forecast incremental expenditures for 2012 and 2013, described further below, to continue to provide the expected level of service.

The total forecast O&M for the Mainland Finance and Regulatory Affairs departments in 2012 of $11.1 million is comprised of the following:

- $7.44 million of compensation and related costs for the 69 COPE and M&E staff. The employee group is a mix of professionals (Chartered Accountants, Certified General Accountants, Certified Management Accountants and MBA graduates) holding management and senior analyst positions, and other non professional staff providing clerical and administrative services;

- $3.35 million of fees (including BCUC quarterly assessments, audit and filing fees, bank charges, contractor fees and other); and
- $0.28 million for employee training costs, travel expenses, miscellaneous administrative costs, materials and supplies, and professional membership dues.

The table below shows the incremental change in the Mainland Finance and Regulatory Affairs department O&M for 2012 and 2013.

Table 5.3-66: Increased O&M is Required to Stakeholder Needs and Expectations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	9,953	(1)	417	-	640	-	62	1,118	11,071
2013	11,071	-	328	-	-	-	-	328	11,399

CUSTOMER & STAKEHOLDER EXPECTATIONS

In 2012, the $640 thousand increase in this category includes the following: $300 thousand to reflect recent experience of higher BCUC quarterly assessments (in 2010 the actual BCUC fees were $300 thousand greater than the approved amount), $250 thousand for expected higher levels of accounting audit fees due to the IFRS implementation which does not allow the use of rate regulated accounting, and $90 thousand due to the new requirements around emission reporting as described in Section 5.3.14.3 (starting 2011 the *Greenhouse Gas Emissions Act* requires external verification/audit of greenhouse gas emissions reporting).

SERVICE STANDARDS & RELIABILITY

In 2012, the $62 thousand increase in this category is due to non-labour inflation.

5.3.15.5 Finance and Regulatory Affairs 2012 and 2013 Forecast - Vancouver Island

Finance and Regulatory Affairs O&M in Vancouver Island consists of BCUC Quarterly Assessments, audit fees and bank charges. The table below shows the incremental change in the Finance and Regulatory Affairs department O&M for 2012 and 2013.

Table 5.3-67: Finance & Regulatory Incremental O&M on Vancouver Island

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	383	(0)	-	-	110	-	-	110	493
2013	493	-	-	-	-	-	-	-	493

CUSTOMER & STAKEHOLDER EXPECTATIONS

The 2012 forecast increase of $110 thousand in this category includes the following: $50 thousand increase in BCUC quarterly assessments; $50 thousand increase in accounting audit fees; and $10 thousand increase driven by the government policy around emission reporting. The rationale for seeking these increases is discussed in Section 5.3.15.4, above.

In 2013, the total Vancouver Island O&M forecast for the Finance and Regulatory Affairs is expected to remain unchanged from the 2012 level.

5.3.15.6 Finance and Regulatory Affairs Summary

The increases in Finance and Regulatory Affairs O&M sought in this Application are primarily driven by inflation and changes in Stakeholder Expectations. They represent the resources needed to meet compliance standards and the requirements of regulatory stakeholders.

5.3.16 CORPORATE

5.3.16.1 Corporate Departmental Overview

The Corporate department provides overall management and leadership for the FortisBC Energy Utilities.

The Corporate department centralizes certain corporate wide cost items including: external legal fees, company insurance premiums, the retiree portions of the pension expense and the OPEB costs, FortisBC Holdings Inc. (“FHI”) corporate services fees, industry association fees (i.e. Canadian Gas Association, Western Energy Institute), shared service charges and recoveries between affiliated utilities and shared service recoveries from CMAE, and recoveries from non-regulated businesses.

5.3.16.2 Corporate O&M Expenditures and Employees

The overall O&M and employee labour requirements for the Corporate department for the four regions are outlined in Tables 5.3-68 and 5.3-69 below. These forecast expenditures reflect the allocation of common costs to the various Companies as discussed further in Section 5.3.18.

Table 5.3-68: Corporate O&M for the Forecast Period

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 11,274	$ 13,915	$ 11,201	$ 11,201	$ 7,266	$ 7,424
Vancouver Island	$ 11,057	$ 10,506	$ 11,065	$ 11,065	$ 12,625	$ 12,522
Whistler	$ 251	$ 264	$ 261	$ 261	$ 330	$ 331
Fort Nelson*	$ 317	$ 321	$ 329	$ 329	$ 522	$ 547
Total	$ 22,898	$ 25,007	$ 22,856	$ 22,856	$ 20,743	$ 20,824

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

Table 5.3-69: Staffing in the Corporate Department

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	2	1	2	1	1	1
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson						
Total	2	1	2	1	1	1

There are several cost drivers for the Corporate operating costs. Corporate legal fees are influenced by the level of external legal support required by the different departments in the FortisBC Energy Utilities. The Companies' insurance premiums are affected by a number of factors such as the insurance company's insured losses, coverage levels and investment income.

In addition, included under the Corporate department are the shared services costs/recoveries between regulated affiliates as well as the corporate services management fee from FHI. The amounts of inter-company charges are based on the level of activities performed and are governed by the Shared Services Agreements and the Corporate Services Agreement. These agreements benefits the organizations involved as they enable the FEU to harvest the benefits of economies of scale by having a single corporate management and support structure while avoiding duplication of work, and allowing customers to benefit from the efficiencies realized.

For 2010 and 2011 in the Whistler and Fort Nelson regions, O&M tracked very close to the approved amounts. In 2010, the $2.59 million higher cost for the Mainland region is primarily driven by executive retirements and the $550 thousand favourable variance on Vancouver Island was due to lower support costs including employee incentive plan related costs.

With the retirement of FEU's past president in 2010, the number of employees became one and is expected to remain unchanged during the forecast period.

The changes in Corporate O&M for the forecast periods are described in Section 5.3.16.3 thorough 5.3.16.6 below.

5.3.16.3 Corporate 2012 and 2013 Forecast - Mainland

The total Mainland O&M forecast for the Corporate department in 2012 of $7.27 million is comprised of the following: $10.72 million for the FHI corporate services fee, $4.4 million for insurance premiums, $1.29 million for retiree portions of employee pension and OPEB expenses, $1.4 million for supporting costs, $623 thousand for corporate legal expenses, and $467 thousand in cross charges from FortisBC Inc.; offset by a $11.02 million credit for shared services recoveries from Vancouver Island, Whistler, Fort Nelson, Thermal Energy Services, and CMAE.

In addition, included in the $7.27 million is a one-time $616 thousand credit for a shared services true-up. In its 2010 – 2011 Revenue Requirement Application, FEI proposed to include in its 2012 O&M forecast a two year cumulative shared services true-up of actual costs between FEI and FEVI and FEW. Consistent with this approach, included in the 2012 Corporate O&M forecast is a $616 thousand one time true-up of the shared services recoveries ($600 thousand from FEVI and $16 thousand from FEW.) These estimates are based on the observed 2010 actual levels of shared services between FEI and other FEU Companies. In 2010, shared Services provided to FEVI were $300 thousand higher than approved, whereas the shared Services provided to FEW were $8 thousand higher than the approved. The Companies have forecast the 2011 level of Shared Services to mirror the observed 2010 actual levels, so the true-up for each year is the same amount.

Table 5.3-70 below shows the year over year changes broken down by the five cost drivers.

Table 5.3-70: Mainland Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	11,201	(27)	(2,817)	-	-	-	(1,091)	(3,935)	7,266
2013	7,266	-	(485)	-	-	-	643	158	7,424

LABOUR INFLATION AND BENEFITS

The decreases in this category in 2012 and 2013 are due to the decreases in the past service cost component of pensions and OPEBs as described in Section 5.3.2.2.

SERVICE STANDARDS AND RELIABILITY

In 2012, the $1.09 million net decrease in this category includes the following items:

- A decrease in costs resulting from an increase in shared services fee recoveries from Vancouver Island, Fort Nelson and Whistler of $1.67 million and the one-time $616 thousand credit for 2010 and 2011 shared services fee recoveries from FEVI and FEW as described above; offset by
- A $1.07 million increase in the corporate cervices fee from FHI and a $125 thousand increase which is the net result of an increase in executive cross changes from FortisBC Inc. and removing the salary of FEU's past president, and an inflationary increase in supporting costs.

In 2013, the $643 thousand net increase in this category is primarily due to:

- a $616 thousand increase due to the removal of the one-time shared services true-up discussed above;
- a $311 thousand increase in the corporate services fee from FHI;
- $220 thousand in higher insurance premiums representing a 5 percent increase over the 2012 estimate;
- a $46 thousand increase in supporting costs; offset by
- $550 thousand higher shared services recoveries from Vancouver Island, Whistler and CMAE.

Please see Section 5.3.18 for a thorough discussion of Shared Services and Corporate Services.

5.3.16.4 Corporate 2012 and 2013 Forecast - Vancouver Island

The total Vancouver Island O&M forecast for the Corporate department in 2012 of $12.62 million is comprised of the $9.04 million shared service fee allocated from the Mainland, the $600 thousand one-time Shared Service true-up discussed above, $1.14 million corporate service fee allocated from FHI, $174 thousand for retiree portions of employee OPEB and pension expenses, $1.04 million for insurance premiums and $630 thousand of supporting costs.

Please refer to the Table 5.3-71 below for the year over year changes broken down by the five cost drivers.

Table 5.3-71: Vancouver Island Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	11,065	(1)	(684)	-	-	-	2,245	1,560	12,625
2013	12,625	-	(92)	-	-	-	(11)	(103)	12,522

LABOUR INFLATION AND BENEFITS

The decreases in this category in 2012 and 2013 are due to the decreases in the past service cost component of pensions and OPEBs as described in Section 5.3.2.2.

SERVICE STANDARDS AND RELIABILITY

In 2012, the $2.25 million increase in this category is primarily due to a $1.5 million increase in the shared service fee from the Mainland, the $600 thousand one-time true up discussed above, $110 thousand increase in insurance premiums and a $35 thousand increase in supporting costs.

The increase in the shared service fee is reflective of the increase in O&M for the Mainland business areas which provide operational support but do not charge their cost directly to Vancouver Island.

In 2013, the $11 thousand decrease is primarily due to a removal of the $600 thousand one-time shared service true-up, offset by a $500 thousand increase in the shared service fee from the Mainland, $39 thousand increase in the FHI corporate services fee and $50 thousand increase in the insurance premium.

5.3.16.5 Corporate 2012 and 2013 Forecast - Whistler

The total Whistler O&M forecast for the Corporate Services department in 2012 of $330 thousand is comprised of $251 thousand in shared service fees allocated from the Mainland, $48 thousand of corporate services fees from FHI, a $16 thousand one-time true-up of shared services discussed above and $15 thousand of supporting costs.

Table 5.3-72: Whistler Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	261	(1)	-	-	-	-	70	69	330
2013	330	-	-	-	-	-	1	1	331

SERVICE STANDARDS AND RELIABILITY

In 2012 the $70 thousand increase in this category is driven by a $39 thousand increase in the shared service fee from the Mainland, a $16 thousand one-time true up discussed above, and a $15 thousand increase in insurance premiums.

In 2013, the $1 thousand increase is due to a $17 thousand increase in the shared service fee from Mainland offset by the removal of $16 thousand one-time true-up included in 2012 and discussed above.

5.3.16.6 Corporate 2012 and 2013 Forecast - Fort Nelson

For financial reporting purposes, the O&M costs for Fort Nelson are included in the overall operating and maintenance expense of Mainland. For regulatory reporting purposes, an allocation from Mainland Corporate O&M is made, recognizing the functional support provided to Fort Nelson. This approach is consistent with the past practice and was approved by Commission Order No. G-27-08.

The increase in Corporate O&M is driven by an increase in the Mainland O&M which is used as an allocation base for Fort Nelson and the 2012 reclassification of Customer Service costs. Following the in-sourcing of the customer service function in 2012, customer service related costs are no longer being captured under the Customer Service department. Instead these costs are included as part of Corporate costs and calculated based on the methodology describe above.

Table 5.3-73: Fort Nelson Corporate Incremental O&M

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012*	329	-	-	-	-	-	193	193	522
2013	522	-	-	-	-	-	25	25	547

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

5.3.16.7 Corporate Summary

For 2010 and 2011, FEU and stakeholders agreed that the requested level of Corporate O&M was appropriate to provide the required leadership to the Companies in an effective and efficient manner. The Corporate department requires the above levels of forecast expenditures for 2012 and 2013 and believes the forecast expenditures are reasonable and appropriate.

5.3.17 CAPITALIZED OVERHEADS

As part of the 2010-2011 RRA, the Utilities had undertaken a study of their overhead capitalized activities. The results of that study indicated an appropriate overhead capitalization rate as applied to gross O&M of 8 percent for Mainland and Fort Nelson, and 5 percent for Vancouver Island and Whistler.

As part of the 2010-2011 NSA for the Mainland, the Parties agreed to a change in the overheads capitalized rate to 14 percent of Gross O&M for 2010 and 2011 which reflected the approximate actual overheads capitalized rate for 2009. This rate of 14 percent was subsequently approved for the Vancouver Island, Whistler, and Fort Nelson service areas.

FEU is of the opinion that there has been no material change in utility operations since that time that would necessitate a further review of the overheads capitalized rate. Therefore, at this time FEU are proposing that the overheads capitalization rate remain at 14 percent of Gross O&M for all utilities during the 2012 and 2013 test years.

5.3.18 CORPORATE AND SHARED SERVICES

5.3.18.1 Corporate Services

The corporate services function consists of certain specialized functions that reside in FHI and Fortis Inc. and that provide expertise to the FEU. These services are shared, providing economies of scale to the FEU. The costs are allocates to each of FEI, FEVI and FEW.

Since the Corporate Services costs and allocations were last determined in 2009, there has been a limited amount of change. The increase is attributable primarily to inflation and the loss of sundry income from the rental of poles at Fortis Inc. The sundry income had previously helped alleviate costs in the FEU but this source of revenue is expected to cease in 2011. Additionally, costs are higher due to higher headcount in functions like Internal Audit and Taxation where certain consulting services have been brought in-house to increase in-house capabilities. Previously, some of these services would have been provided by external resources. The benefit to the customer of this approach is an increased knowledge base today and in the future in order to maintain reasonable costs. In this application, FHI is proposing to continue with the allocation of the same types of costs that were allocated in 2010 and 2011, reflecting FHI’s current ownership structure which has not changed since 2009.

Today, as in 2010 and 2011, the Corporate Services are contracted to FEU through FHI. These costs are consistent with those include in the 2010/2011 RRA as reviewed by KPMG. The report of KPMG was filed with the 2010-2011 RRA in 2009.

FORTIS INC. CORPORATE SERVICES COSTS

The services to be performed by Fortis Inc. are consistent with the services provided by Fortis Inc. to FHI in 2009, which were approved by the Commission. At the Fortis Inc. level, these services are strategic in nature and consist of the following functions:

- Executive (CEO and CFO) - provide strategic direction, leadership and management for Fortis Inc., manage the organizational structure, financial planning, maintaining controls and internal systems, employee relations, external communication, board relations, regulatory compliance, provision of legal services, maintain internal and external audit activities, and corporate financing and budgeting.
- Treasury and Taxation - performs Fortis Inc. Treasury services and provides oversight to subsidiary companies for debt and equity financings, maintaining the capital structure, corporate cash management and forecasting, management of hedging activities, preparation of corporate tax returns, tax planning, coordinating corporate tax audits, rating agency process, and corporate credit facilities.
- Investor Relations - manage analyst, investor and shareholder communications, coordinate Fortis Inc. annual general meeting, preparation of quarterly investor relations reports, manage public and media relations, maintain Fortis Inc. website, manage dividend reinvestment and share purchase plans, and oversight over the Annual Report preparation process.
- Financial Reporting - preparation of monthly, quarterly and annual consolidated and non-consolidated Fortis Inc. financial statements, coordination with external auditors, analysis of financial information, preparation of the Annual Information Form for Fortis Inc., Annual Report for Fortis Inc., quarterly and annual Management Discussion and Analysis for Fortis Inc. and other continuous disclosure documents for Fortis Inc., coordinate consistent accounting policy treatment across the Fortis group, oversight and coordination of conversion to International Financial Reporting Standards, preparation of the company-wide quarterly forecast consolidated earnings for Fortis Inc. and EPS and maintaining internal controls over financial reporting for Fortis Inc.
- Internal Audit - performs Fortis Inc. internal audit activities, provides oversight over the internal audit function at the Fortis subsidiary companies, administers and monitors reports of allegations of suspected improper conduct or wrong doing, development of a company-wide Enterprise Risk Management program approach.
- Corporate Secretary and Board of Directors - annual strategic planning and risk management activities, selecting and evaluating the CEO, appoint officers, review and approve all material transactions, evaluate Fortis Inc.'s internal controls relating to financial and management information systems, establish and maintain policies regarding communication and disclosure with stakeholders, develop and maintain governance procedures.

The eligible costs for allocations to FHI and other Fortis Inc. owned entities are summarized in the following table. The FHI allocation has been included in the totals in Table 5.3-75 below.

Table 5.3-74: Eligible Cost Allocations to FHI and other Fortis Inc. Owned Entities

Estimated 2012 Estimated Costs Services (in 000s)	FHI 44.31%	Other ~~1~~ 55.69%	Total 100%
Executive	1,682	2,114	3,796
Treasury	220	276	496
Investor Relations	702	883	1,585
Financial Reporting	801	1,007	1,808
Internal Audit	73	91	164
Board of Directors	788	991	1,779
Other	1,309	1,646	2,955
Subtotal	5,575	7,008	12,583
Less: Fortis Properties Management Fee Revenue	(665)	(835)	(1,500)
Total	4,910	6,173	11,083

The forecast costs for 2013 includes a three percent increase in overall costs multiplied by the same allocation percentage of 44.31%. The allocation percentage represents the total assets of FHI compared to the total assets of Fortis Inc. Fortis Inc. has consistently allocated costs across its regulated holdings but using the percentage of assets as its allocation factor.

FORTISBC HOLDINGS INC. CORPORATE SERVICES COSTS

The corporate services group at FHI are responsible for providing key corporate function directly to each of the FEU, and consists of the following functions:

- Board of Directors - ensure all continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, manage the relationship and corporate activities of the FHI Board of Directors, and develop and maintain governance procedures and policies. The Board of Directors is a joint Board that is shared with FortisBC Inc. All costs incurred for compensation and other Board expenses have been shared between FHI and FBC based on an expanded Massachusetts method which incorporates the assets, payroll and net tangible assets. The costs reflected in this Application are the costs less any amounts recoverable from FortisBC Inc.
- Corporate Development, Treasury and Cash Management – execute short and long term financings, cash management and forecasting, arrange operating credit facilities, and negotiate bank-service fees for all FEU entities; responsible for treasury related controls and compliance, compliance reporting, hedging of interest rate and foreign exchange risks, managing the rating agencies, maintaining bank and debt investor relationships, investor and shareholder communication, preparation of annual/quarterly disclosure documents, preparation of the annual report, preparing regulatory submissions in support of ROE, capital structure and financing related matters, providing credit and counter-party credit risk management and assistance in negotiating physical

and derivative commodity contracts to the Energy Supply and Resource Development department for both the gas and electric, assessment and monitoring of physical and financial counterparties, developing appropriate derivative and counterparty policies.

- External Reporting – preparation of monthly, quarterly and annual consolidated and non-consolidated financial statements (for FHI, FEI, FEVI and FEW), coordination with external auditors, analysis of financial information, assisting in the preparation of the Annual Information Form, quarterly and annual Management Discussion and Analysis and other continuous disclosure documents, coordinating consistent accounting policy treatment across the FEU, preparing for and implementing GAAP changes, preparing quarterly forecasts of consolidated earnings and maintaining internal controls over financial reporting.
- Taxation Services – provides a full range of services in income and commodity taxes including financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), tax compliance (filing of tax returns, coordination of tax audits), regulatory tax accounting (tax calculations for rate cases and annual reports), tax planning including guidance and support for significant transactions, and tax dispute management and resolution.
- Internal Audit – developing, planning and conducting audits/reviews, conducting annual risk assessment processes, monitoring and evaluating the effectiveness and efficiency of internal controls.
- Risk Management and Insurance Services – ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and ensuring an appropriate and prudent insurance program.
- Legal – provides all legal services and counsel to various departments on issues including regulatory, environmental, business development, employment, securities, financing and intellectual property, and manages legal matters that have been outsourced to outside legal counsel.
- Human Resources Compensation and Planning – consults with management on the maintenance, development and governance of employees and retirees, provides assistance on annual wage and salary increases, ensure that employment practices are in compliance with applicable regulations and legislation.

TOTAL POOL OF COSTS FOR ALLOCATION TO FEU

The costs discussed above that are incurred by Fortis Inc. on behalf of the FEU are allocated to FHI. These costs and other corporate costs incurred by FHI on behalf of the FEU form the pool of costs that are eligible to be allocated to each of FEI, FEVI and FEW.

Of the pool of costs, certain costs incurred in support of the utilities are eligible for inclusion in customer rates and are passed on to the utilities in the form of a corporate services fee. Other costs are unique to the holding company and have been excluded from the calculation of the FHI corporate services fee. These excluded costs are:

- All identifiable corporate development and capital management (shareholder related) costs;
- Legal fees incurred for non-regulated entities;
- Pension costs related to executive bonuses;
- All fees associated with FHI's International operations; and
- Ineligible components of the Fortis Inc. management fee including Defined Benefit Pension, Defined Contribution Supplemental Employee Retirement Plan on executive bonuses and stock option costs which were not already excluded by Fortis Inc.

The following table is a summary of the actual total corporate services costs (net of the exclusions noted above) that form the total pool of costs that is allocated to the FEU and shows the costs incurred in 2010, a forecast of 2011 costs and forecast costs for 2012 and 2013.

Table 5.3-75: Corporate Services Costs 2010 through 2013

Services (in 000)	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast
Board of Directors (12 Directors)	772	672	666	686
External Financial Reporting and Consolidation	1,151	970	966	995
Human Resources Compensation & Planning	370	229	285	294
Internal Audit	480	599	623	642
Legal	1,151	1,220	1,160	1,195
Risk Management and Insurance	268	284	301	310
Taxation	607	708	731	753
Treasury and Cash Management	725	800	824	849
Facilities and Support	942	912	949	977
Other Compension and Benefits	1,388	1,488	1,437	1,480
Fortis Inc Management Fee	3,801	4,210	4,910	5,057
	11,655	12,092	12,852	13,238

ALLOCATION OF CORPORATE SERVICES COSTS

The costs from Fortis Inc. are allocated to FHI using the assets by subsidiary driver which is a valid cost driver given the organizational structure of Fortis Inc. The methodology selected by FHI to allocate the corporate services costs charged to FEI, FEVI and FEW incorporates the

Massachusetts formula,[93] which is the same allocation methodology previously approved by the Commission for 2010 and 2011.

The results of the review indicate that the annual Corporate Services to be allocated from FHI to FEI, FEVI and FEW are as shown in the following table.

Table 5.3-76: Annual Corporate Services to be Allocated from FHI

	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast
FEI	9,557	9,652	10,719	11,031
FEVI	1,087	1,097	1,140	1,196
FEW	48	49	48	50
Other	963	1,294	945	961
	11,655	12,092	12,852	13,238

The overall structure of FHI has remained relatively constant since 2009. FHI has reviewed the Corporate Services approach as part of this RRA. The same approach and methodologies, which were reviewed and validated by KPMG for the 2010/2011 RRA, have been used by management. FEI considers the results to be reasonable and representative of the activities and their value provided by FHI to FEI, FEVI and FEW. The increase in the fee is generally due to higher headcount in certain functions to support the businesses plus higher costs due to inflation. The higher headcount is in Internal Audit and Taxation. The other functional areas are generally higher due to inflation increasing the costs for 2012 and 2013. Additionally, the management fee from Fortis Inc. to FHI is higher due to the loss of rental pole revenue which lowered the fees charged from Fortis to its subsidiaries, reducing the previous management fee charged by Fortis. Amending agreements between FHI, FEI, FEVI and FEW are included in Appendix L-2.

5.3.18.2 Shared Services

Sharing of resources amongst the FEU under Shared Services arrangements enables the Companies to maintain the benefits of economies of scale by having a single management and support structure while avoiding duplication of work and allowing customers to benefit from the efficiencies realized.

FEI completed a review of the Shared Services agreement and cost allocation approach as part of the 2010-2011 RRA with validation by KPMG. No changes in methodology have occurred

93 The Massachusetts Formula is in extensive use in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that cannot be directly assigned.

since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place.

Common services delivered on a Shared Services basis include:

- Corporate;
- Finance and Regulatory Affairs;
- Customer Service;
- Human Resources;
- Environmental & Safety
- Energy Supply and Resource Development;
- Information Technology;
- Facilities;
- Operations Support;
- Operations Engineering;
- Transmission;
- Distribution; and
- Energy Solutions & External Relations.

SUMMARY OF RESULTS

The following table provides the comparative amounts of Total Shared Services Costs for FEU.

Table 5.3-77: Total Shared Services Costs

('000's)	Approved		Forecast					
	2010	2011	Incremental 2012 vs 2011	% Allocation	2012	Incremental 2013 vs 2012	% Allocation	2013
Total Costs included in Shared Services Pool	70,313	73,338	14,202	100.00%	87,540	4,710	100.00%	92,250
Allocated to FEVI	7,239	7,541	1,499	10.6%	9,040	498	10.6%	9,538
Allocated to FEW	202	212	39	0.3%	251	13	0.3%	264
Allocated to FEI	62,872	65,585	12,664	89.2%	78,249	4,199	89.2%	82,448

FEI AND FEVI SHARED SERVICES

The Shared Services agreement between FEVI and FEI including the method of allocation is unchanged from that filed in Appendix H-4-a of the 2010-2011 RRA[94]. The results of the Shared Service agreement indicate that the amount of annual Shared Services to be allocated from FEI to FEVI is estimated to be $9.0 million in 2012 and $9.5 million in 2013 as illustrated in Table 5.3-77.

The current allocation in comparison to the 2011 projection is higher with increased levels and scope of work driving the increase. The increases in the 2012 Forecast recoveries compared to the 2011 projection total $1.5 million with incremental recoveries by business area as follows:

- Customer Services - $650 thousand for Centralized Support Services that the Customer Service department will receive from Information Technology, Human Resources and Facilities. Since the Centralized Support Services costs will be incurred in the respective departments rather than in Customer Service department, it is appropriate that these costs are allocated to FEVI through Shared Services. In the past, under the ABSU agreement, these costs would have been directly billed to FEVI.
- Distribution, Transmission and Information Technology - $430 thousand for Service Standards and Reliability costs to support ongoing integrity and asset management activities related to system sustainment and improvements to the long term asset management plan. The majority of these costs are incurred by Distribution, Transmission and IT departments. For a detailed explanation of the Service Standards and Reliability increase, please refer to Section 5.3.5 for Distribution and Transmission, and Section 5.3.9 for IT.
- Labour inflation - $230 thousand allocated for Shared Services from FEI to FEVI.

94 Costs are generally allocated on the basis of customers, employees, and, management estimates of time.

- Human Resources - $50 thousand due to increased requirements resulting from retirement and related hiring activity. Please refer to a discussion of demographics in Human Resources in Section 5.3.13.
- Energy Solutions & External Relations and Finance & Regulatory - $140 thousand due to stakeholder requests to improve resource planning, forecasting, and energy analysis and planning activities. Please refer to Section 5.3.6 for a thorough discussion of the Customer and Stakeholder Expectation cost driver in ES&ER.

In 2013, Shared Services are expected to increase by a further $0.5 million with approximately half of the increase due to system sustainment, service standards and reliability, and the remaining half for labour inflation.

Despite the higher costs, FEI and FEVI believe that by providing common services through a Shared Services approach, the costs are being optimized between the two organizations for the benefit of all customers. To properly reflect the value of activities provided by FEI to FEVI, the Company requests that the Commission approve the allocation of costs for Shared Services between FEI and FEVI for the years 2012 and 2013.

FEI AND FEW SHARED SERVICES

The Shared Service agreement between FEW and FEI including the method of allocation is unchanged from that filed in Appendix H-4-b of the 2010-2011 RRA. The amount of annual Shared Services to be allocated from FEI to FEW is estimated to be approximately $0.3 million in 2012 and 2013. The drivers of these changes are as explained above for FEVI.

To properly reflect the value of activities provided by FEI to FEW, the Company requests that the Commission approve the allocation of costs for Shared Services between FEI and FEW for the years 2012 and 2013.

PROVISION OF SERVICES TO THERMAL ENERGY SERVICES

In Commission Order No. G-141-09, FEI agreed to charge Thermal Energy Services customers $0.5 million for 2010 and $0.5 million for 2011 for services provided by the gas utility. In this Application, FEI has undertaken a review of which services should be included in this administrative charge and what the charge should be for 2012 and 2013. Administrative services include those services not directly charged or chargeable and include the following categories:

- Executive: time to review current status of projects, monitor status of projects and reviewing and approving potential projects.
- Finance: management and financial reporting and accounts payable.

- Regulatory affairs: reviewing cost of service models, tariffs and project management.
- Human Resources: recruiting and compensation and benefits.
- Information technology: IT support to existing employees charging time directly to the AES deferral.
- Facilities: allocation of facilities costs for employees charging directly into the AES deferral account. The facilities include space in the Surrey Operations Centre, Garbally/Langford and the Burnaby facility.

Based on the review, FEI has estimated that a charge of approximately $0.5 million for both 2012 and 2013 be included as a recovery of overheads for the benefit of FEI and its ratepayers. This charge represents the expected administrative costs of supporting the AES business.

SHARING OF SERVICES WITH FORTISBC INC.

In the summer of 2010, FEU and FortisBC Inc. ("FBC") began having a common, shared Executive Management team. The shared responsibilities between the entities facilitates the FEU and FBC cross charging each other for the time each Executive expects to spend with their new responsibilities. FEU are charging FBC for those Executives who are FEU employees and have responsibilities in FBC, and receiving charges for FBC Executives who have responsibilities at FEU. Additionally, in a limited a number of circumstances, a number of FEI employees perform work for FBC, and vice versa for certain employees in FBC providing services to FEI. Currently, the cross charge includes a fully loaded wage with benefits and concessions plus an overhead charge of 10 percent and a one hundred dollars per day facility fee.

In order to simplify this process between similar regulated entities, FEI is proposing to simplify the cross charges between FEU and FBC. In this Application, the FEU are requesting to allow for charges between these regulated entities to be based on a fully loaded benefits and concessions charge but to not include overheads or a facilities fee. The current policy requires that charges between FEI and FBC include the overhead and facilities fee. The Shared Services Agreement between FEI and FBC is included in Appendix L-3.

5.3.18.3 Transfer Pricing Policy and Code of Conduct Review

Since they were originally established in 1997 and approved by the Commission in Letter L-64-1997, the Code of Conduct ("COC") and Transfer Pricing Policy ("TPP") have served to govern the relationships between FEU and Non-Regulated Businesses ("NRB") regarding the provision of utility resources for activities including sharing of utility resources, the treatment of customer, utility or confidential information and the nature of the relationship between FEU and NRBs. These policies were reviewed as part of the 2010 and 2011 Revenue Requirements Application where the Company did not propose any changes. As part of this application, FEU has reviewed the COC and TPP to assess their appropriateness and whether amendments are required.

FEU propose no changes to the existing COC and TPP. Both policies are expected to continue to provide appropriate direction and rules to govern the interaction of FEU and NRBs during the period of the current Application. Further, FEU believe that the processes in place and the independent compliance reviews conducted annually by FEU's Internal Audit provide a sufficient level of assurance to ratepayers, stakeholders and the Commission.

COMPLIANCE WITH CODE OF CONDUCT AND TRANSFER PRICING POLICIES

The FEU comply with the COC and the TPP for provision of Company resources and services by having their employees charge out their time to NRBs. Employees currently keep track of the time they spend on NRB activities. Their salary costs, loaded for benefits and concessions, and an overhead charge for the use of facilities and other resources, and in some cases, an availability and supervisory surcharge are charged to the NRB. This process is managed through the continuing services contracts between the Company, and NRBs. The following is a list of entities which are managed through this process:

- FortisBC Holdings Inc.
- FortisBC Alternative Energy Services Inc (formerly Terasen Energy Services Inc.).
- Inland Energy Corp.
- FortisBC Huntingdon Inc.

Non-utility activities performed on behalf of FHI and other NRBs are charged 100 per cent to FHI and to the NRBs respectively. This is managed through monthly timesheets and appropriate charge codes for each NRB. For 2012 and 2013, it is expected that the FEU will charge FHI and other NRBs and reduce the cost of service through the recovery of overheads for the benefit of FEI and its customers. The overhead recoveries are included in Other Revenues in Section 5.5.

To ensure that FEU's practices and processes comply with the policies, FEU's Internal Audit group completes a review of compliance with the COC and TPP annually with a report provided summarizing the results of the review. This practice has worked very well over the years with very few issues or exceptions. Those few that were identified were promptly addressed by management and appropriately remedied.

In summary, FEU has reviewed the existing TPP and COC and is requesting that the existing policy changes to accommodate charges between two affiliated regulated utilities, FEU and

FBC. The change being requested should simplify the charges between the two entities as both move towards a more shared management structure. Additionally, FEU has reviewed the overhead charge between the gas customers and the AES customers and has proposed a fee based on the expected utilization of services by the AES customers. Other than these proposed changes, the current transfer pricing policies are appropriate for the period of this Application.

5.3.18.4 Summary of Corporate and Shared Services

In summary, this section has described the corporate services provided by Fortis Inc. and FHI to the FEU and how the FEU share costs amongst each other and with FBC. The relationship between the FEU, FHI and Fortis Inc. is generally unchanged from the time of filing of the 2010/2011 RRA. Certain organizational changes as a result of a shared executive team have changed the relationship between the FEU and FBC. The shared executive team has resulted in cross charges between FEU and FBC for the portion of executive time spent on each others business. Shared services across the FEU is similar to what was filed in the 2010/2011 RRA. While the costs are different, the drivers of those costs are as filed in the 2010/2011 RRA.

5.3.19 SUMMARY OF OPERATIONS AND MAINTENANCE EXPENSE

The Companies' 2012 and 2013 O&M forecasts reflect the changes in operating requirements that are anticipated over the forecast period. In particular, incremental funding requests are driven by five requirements – labour inflation and benefits, codes and regulations, customer and stakeholder expectations, demographics, and a continued focus on service standards and reliability. In total, these drivers serve to increase O&M by 4.8 percent in each of the forecast years. The FEU believe that the O&M levels that have been forecast prudently reflect the known and expected impacts of their operating environment, and required increases related to safety and regulatory requirements.

5.4 Depreciation and Amortization

5.4.1 INTRODUCTION TO DEPRECIATION AND AMORTIZATION

The FortisBC Energy Utilities received approval to update their depreciation rates, excluding any amount for recovery of negative salvage, effective January 1, 2010. Excerpts from the relevant Commission Orders follow.

Appendix A to Order G-141-09 approving the Negotiated Settlement Agreement in the 2010-2011 FEI (then Terasen Gas Inc.) Revenue Requirement Application states:

"22. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010…

The Parties agree that TGI will undertake an updated depreciation study to be included as part of TGI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

23. Negative Salvage Values

On an annual basis, TGI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGI historically, and with this RRA TGI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($8.038 million and $11.29 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

24. Unrecovered Losses

> *Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:*
>
> *"Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."*
>
> *Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 percent for the provision of utility service to ratepayers (as discussed in the response to BCUC IR 2.131.1.4). The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this agreement. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application."*

Appendix A to Order G-140-09, approving the Negotiated Settlement Agreement in the 2010-2011 FEVI (then Terasen Gas (Vancouver Island) Inc.) Revenue Requirement Application states:

> *"16. Depreciation Study*
>
> *The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010…The Parties agree that TGVI will undertake an updated depreciation study to be included as part of TGVI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGVI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.*
>
> *17. Negative Salvage Values*
>
> *On an annual basis, TGVI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment, which was approved as recently as 2004, along with an estimate of the salvage amount to be included in depreciation rates recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGVI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGVI historically, and with this RRA TGVI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.*

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($0.343 million and $0.344 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGVI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

18. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

"Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 percent for the provision of utility service to ratepayers (BCUC IR 1.112.1). The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this Agreement. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application."

Appendix A to Order G-138-10 and Reasons for Decision in the FEW (then Terasen Gas (Whistler) Inc.) 2010-2011 Revenue Requirements and Rates Application states:

"2.7.3 Depreciation Expense

The Commission Panel takes note of the depreciation methods and policies adopted for TGI and TGVI as part of their respective Negotiated Settlement Agreements for 2010 and 2011. As noted in previous sections above, the Commission Panel generally agrees that it is beneficial to align TGW's policies and methodologies with those of TGI and

> *TGVI where appropriate. Accordingly, the Commission Panel approves the depreciation policies and practices requested by TGW, for the forecast years 2010 and 2011, subject to the removal of the negative salvage provision from the composite depreciation rate as discussed above.*
>
> *Notwithstanding the foregoing approval, the Commission Panel is not convinced that the elimination of the negative salvage provision in the determination of the composite depreciation rate is appropriate on an ongoing basis. TGW is directed to include evidence with respect to negative salvage in future revenue requirement applications. The Commission Panel also suggests that consistent with the above comments concerning the alignment of TGW's policies and methodologies with those of TGI and TGVI, those utilities also include evidence with respect to negative salvage in their future revenue requirement applications."*

Appendix A to Order G-27-11 and Reasons for Decision in the FEI Fort Nelson (then Terasen Gas Inc. – Fort Nelson Service Area) 2011 Revenue Requirements Application:

> *"3.6.2 Changes in Depreciation*
>
> *The Commission approves the requested depreciation increases for implementation effective January 1, 2010 to align with the approved depreciation rates of TGI which are the most recent estimates of the useful life of the Utility's assets."*

This section of the Application discusses the information that the FEU committed to provide as part of the above excerpts.

First, the Companies summarize the results of their updated Depreciation Study in Section 5.4.2 and Appendix E-1. This study addresses the methodology and rates for net negative salvage to be included in cost of service for future periods. The Companies have involved Commission staff and a depreciation rate specialist in determining the requirements of the study.

Second, the Companies summarize the historical and proposed treatment of negative salvage in Section 5.4.3 and provide a report on Asset Retirement Obligations in Appendix E-2. The Companies have involved Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and have included the documentation to support the rates in the Depreciation Study.

Finally, the Companies summarize the asset retirement and accounting processes at the utilities and how the processes lead to the financial gains/losses recorded, and provide explanations and reasons for the losses recorded for each of the asset categories noted. This information is included in Section 5.4.4 and an Asset Loss Report provided in Appendix E-3.

5.4.2 DEPRECIATION STUDY AND RATES

Overall, the current Depreciation Study's results are consistent with the previous study's results which were approved for use effective January 1, 2010. Similar to the previous study, Gannett Fleming Valuation and Rate Consultants Inc. ("Gannett Fleming"), a leading Depreciation, Valuation and Ratemaking consulting firm in North America, was contracted to perform the review of the FEU depreciation rates. The current study which is included in Appendix E-1, has been prepared based on gas plant-in-service as of December 31, 2009 for FEU's assets. FEU considers that the current study's recommendations are applicable for the 2012 and 2013 forecast period as Gannett Fleming recommends that complete studies be performed every three to five years to re-evaluate depreciation rates.

As in the prior study, Gannett Fleming has estimated the depreciation rates using various statistical methods, operational interviews with FEU staff and informed judgement based on their experience in the natural gas industry. Straight-line depreciation is developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics and then accounting for the accumulated depreciation already booked in that class. In addition, the current study has been prepared in conformance with International Financial Reporting Standards and US GAAP reporting requirements.

Implementation of the recommended rates, which are set out in the following Tables 5.4-1 to 5.4-3, that were developed using the Average Service Life ("ASL") depreciation methodology would change the average composite rate for FEI, FEVI and FEW from 3.0 percent, 2.6 percent and 2.2 percent to 3.1 percent, 2.6 percent and 2.4 percent respectively. Total depreciation expense for FEI, FEVI and FEW would change approximately +$4.6 million, -$0.3 million and +0.03 million due to changes in the depreciation rates. This excludes the effects on depreciation expense of additions and retirements to PP&E. Rates noted with an asterisk in the tables below are rates that are not included in the Depreciation Study since they have been set through separate regulatory applications (i.e. Biogas, Natural Gas for Transport, etc.) or specific rates set by the FEU (i.e. lease structures/buildings based on lease terms, etc).

Table 5.4-1: FEI - Impact of Implementing Recommended Depreciation Rates[95]

Line #	Class	Description	Existing 2011 Rate	Recommended 2012 Rate	Depreciation Based on 2011 Rate	Depreciation Based on 2012 Rate	Increase + / Decrease -
1	175-00	Unamortized Conversion Expense *	1.0%	1.0%	7,770	7,770	-
2	401-01	Franchises and Consents	19.76%	49.19%	19,609	48,814	29,205
3	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	5,052,518	5,052,518	-
4	402-02	Computer S/W-Applic 5 Year	20.00%	20.00%	3,375,631	3,375,631	-
5	402-03	Intangible Plant	2.14%	2.38%	14,714	16,364	1,650
6	402-11	Plant Acquisitions and Adjustments	23.66%	57.14%	14,777	35,688	20,910
7	432-00	Mfg. Gas Structures	3.28%	3.38%	15,203	15,667	464
8	433-00	Mfg. Gas Equipment	6.30%	6.63%	9,194	9,676	482
9	434-00	Mfg. Gas Holders	3.90%	2.35%	13,946	8,403	(5,543)
10	436-00	Mfg. Gas Compressor Equipement	4.96%	5.16%	2,644	2,751	107
11	437-00	Mfg. Gas Meas/Reg Equipment	19.50%	15.89%	60,342	49,171	(11,171)
12	442-00	LNG Gas Structures	3.65%	3.57%	181,020	177,053	(3,968)
13	443-00	LNG Gas Equipment	2.18%	1.93%	359,570	318,335	(41,235)
14	449-00	LNG Gas Other Equipment	3.36%	4.24%	896,611	1,131,438	234,827
15	462-00	TP Compressor Structures	3.84%	3.74%	565,585	550,856	(14,729)
16	463-00	TP Meas/Reg Structures	4.27%	3.80%	229,706	204,422	(25,284)
17	464-00	TP Other Structures	2.88%	2.83%	173,211	170,204	(3,007)
18	465-00	TP Transmission Pipeline	1.63%	1.44%	12,823,038	11,328,328	(1,494,710)
19	465-00	TP Mains - Inspection *	14.87%	14.87%	608,683	608,683	-
20	465-10	TP Mains - Byron Creek *	5.00%	5.00%	48,525	48,525	-
21	466-00	TP Compressor Equipment	3.18%	2.87%	3,516,218	3,173,442	(342,776)
22	466-00	TP Compressor Equipment - Overhauls *	4.47%	4.47%	102,160	102,160	-
23	467-10	TP Meas/Reg Equipment	7.19%	4.27%	2,073,508	1,231,416	(842,092)
24	467-02	TP Telemetry Equipment	1.33%	0.31%	87,493	20,393	(67,100)
25	467-20	TP Meas/Reg Equipment - Byron Creek *	4.01%	4.01%	1,553	1,553	-
26	468-00	TP Communications Equipment	5.32%	4.37%	18,401	15,115	(3,286)
27	472-00	DS Structures	3.60%	3.33%	572,054	529,150	(42,904)
28	472-10	DS Structures - Byron Creek *	5.00%	5.00%	5,362	5,362	-
29	473-00	DS Services	2.25%	2.29%	15,440,032	15,714,521	274,489
30	473-01	LILO DS Services	2.20%	5.91%	946,515	2,542,683	1,596,168
31	474-00	DS Meters/Regulators Installations	5.21%	7.44%	7,871,078	11,240,081	3,369,003
32	474-01	LILO DS Meters/Regulators Installations	2.19%	3.72%	351,936	597,809	245,873
33	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	-	-	-
34	475-00	DS Mains	1.89%	1.48%	16,899,394	13,233,388	(3,666,006)
35	475-01	LILO DS Mains	2.00%	4.54%	794,352	1,803,178	1,008,826
36	476-00	DS NGV Fuel Equipment	25.04%	26.54%	256,993	272,388	15,395
37	477-00	DS Telemetering *	0.25%	0.25%	16,235	16,235	-
38	477-10	DS Meas/Reg Additions	5.72%	4.75%	5,037,554	4,183,284	(854,271)
39	477-30	DS Meas/Reg Equipment	0.00%	0.00%	-	-	-
40	478-01	DS Meters	5.31%	7.89%	10,611,070	15,766,731	5,155,661
41	478-11	LILO DS Meters	3.29%	5.23%	329,879	524,398	194,518
42	478-20	DS Instruments	4.03%	3.15%	463,480	362,273	(101,207)
43	472-00	Biogas - Structures and Improvements *	3.60%	3.60%	-	-	-
44	475-10	Biogas - Mains - Municipal Land *	1.48%	1.48%	-	-	-
45	475-20	Biogas - Mains - Private Land *	1.48%	1.48%	4,907	4,907	-
46	418-10	Biogas - Purication Overhaul *	13.33%	13.33%	62,354	62,354	-
47	418-20	Biogas - Purification Upgrader *	6.67%	6.67%	124,802	124,802	-
48	474-10	Biogas - Reg and Meter Installations *	5.21%	5.21%	34,546	34,546	-
49	478-30	Biogas - Meters *	5.31%	5.31%	23,710	23,710	-
50	476-10	NGV - Transport CNG Dispensing Equipment *	5.00%	5.00%	102,910	102,910	-
51	476-20	NGV - Transport LNG Dispensing Equipment *	5.00%	5.00%	87,615	87,615	-
52	476-30	NGV - Transport CNG Foundations *	5.00%	5.00%	22,720	22,720	-
53	476-40	NGV - Transport LNG Foundations *	5.00%	5.00%	19,305	19,305	-
54	476-50	NGV - Transport LNG Pumps *	10.00%	10.00%	83,160	83,160	-
55	476-50	NGV - CNG Dehydrator *	5.00%	5.00%	8,019	8,019	-
56	476-70	NGV - LNG Dehydrator *	5.00%	5.00%	-	-	-
57	482-10	GP (Frame) Structures	3.67%	4.82%	298,520	392,061	93,542
58	482-20	GP (Masonry) Structures	2.50%	2.23%	2,159,032	1,925,856	(233,175)
59	482-30	GP (Leased) Structures *	10.00%	10.00%	26,071	26,071	-
60	483-10	GP Computer Hardware	20.00%	20.00%	4,211,342	4,211,342	-
61	483-20	GP Computer Systems Software	12.50%	12.50%	243,739	243,739	-
62	482-21	GP Computer Systems Software	20.00%	20.00%	0	0	-
63	483-30	GP Office Equipment	6.67%	6.67%	239,110	239,110	-
64	483-40	GP Furniture	5.00%	5.00%	970,903	970,903	-
65	484-00	GP Vehicles	7.70%	5.16%	99,560	66,718	(32,842)
66	485-10	GP Heavy Work Equipment	6.64%	8.96%	18,148	24,489	6,341
67	485-20	GP Heavy Mobile Equipment	8.48%	18.06%	86,792	184,842	98,050
68	486-00	GP Small Tools/Equipment	5.00%	5.00%	2,039,639	2,039,639	-
69	487-20	GP NGV Cylinders	6.67%	6.67%	587	587	-
70	488-10	GP Telephone Equipment	6.67%	6.67%	520,793	520,793	-
71	488-20	GP Radio Equipment	6.67%	6.67%	303,246	303,246	-
72		Total Annual Depreciation			101,659,094	106,219,301	4,560,207
73							
74		Annual Composite Rate			3.0%	3.1%	
75							
	* Numbers above are in actual dollars with depreciation calculated using the January 1, 2012 gross asset values.						

[95] Fort Nelson's composite depreciation rate decreases from 3.2% to 2.9% resulting in a decrease of approximately $30,000 in annual depreciation expense.

Table 5.4-2: FEVI - Impact of Implementing Recommended Depreciation Rates

Line #	Class	Description	Existing 2011 Rate	Recommended 2012 Rate	Depreciation Based on 2011 Rate	Depreciation Based on 2012 Rate	Increase + / Decrease -
1	401-01	Franchise and Consents	3.13%	3.07%	5,940	5,826	(114)
2	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	2,033,965	2,033,965	-
3	402-02	Computer S/W-Applic 5 Year	20.00%	20.00%	612,627	612,627	-
4	402-03	Other Intangible Plant	2.30%	1.88%	28,038	22,918	(5,120)
5	442-00	LNG Gas - Structures *	4.00%	4.00%	692,876	692,876	-
6	443-00	LNG Gas Equipment *	1.67%	1.67%	1,007,683	1,007,683	-
7	448-10	LNG Gas - Piping *	2.50%	2.50%	288,125	288,125	-
8	448-20	LNG Gas - Pre-Treatment *	4.00%	4.00%	1,152,499	1,152,499	-
9	448-30	LNG Gas - Liquefaction Equipment *	2.50%	2.50%	720,312	720,312	-
10	448-40	LNG Gas - Send Out Equipment *	2.50%	2.50%	576,937	576,937	-
11	448-50	LNG Gas - Sub-Station and Electrical *	2.50%	2.50%	557,800	557,800	-
12	448-60	LNG Gas - Control Room *	6.67%	6.67%	392,321	392,321	-
13	449-00	LNG Gas - Other *	2.86%	2.86%	4,923	4,923	-
14	465-00	LNG - Mains *	1.54%	1.54%	91,992	91,992	-
15	467-00	LNG - Measuring and Regulating Equipment *	3.70%	3.70%	202,417	202,417	-
16	462-00	TP Compressor Structures	3.72%	3.56%	433,279	414,643	(18,636)
17	463-00	TP Measurement/Regulating Structures	2.87%	3.02%	215,740	227,016	11,276
18	464-00	TP Other Structures	2.87%	2.85%	3,717	3,691	(26)
19	465-00	TP Transmission Pipeline	1.73%	1.55%	5,674,081	5,083,714	(590,367)
20	465-00	TP Mains - Inspection *	14.29%	14.29%	466,454	466,454	-
21	465-11	IP Transmission Pipeline (Whistler Pipeline)	1.73%	1.43%	785,766	649,506	(136,260)
22	466-00	TP Compressor Equipment	3.19%	2.90%	1,887,810	1,716,191	(171,619)
23	466-00	TP Compressor Equipment - Overhaul *	26.76%	26.76%	1,568,086	1,568,086	-
24	467-10	TP Meas/Reg Equipment	5.59%	4.30%	784,824	603,711	(181,113)
25	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	5.59%	4.00%	18,980	13,581	(5,399)
26	468-00	TP Communications Equipment	10.07%	11.97%	371,915	442,088	70,173
27	472-00	DS Structures	3.21%	3.07%	73,590	70,381	(3,210)
28	473-00	DS Services	1.91%	2.00%	3,407,943	3,568,527	160,584
29	474-00	DS Meters/Regulators Installations	3.45%	5.76%	797,386	1,331,287	533,902
30	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	-	-	-
31	475-00	DS Mains	1.62%	1.49%	4,621,048	4,250,223	(370,825)
32	477-10	DS Meas/Reg Additions	4.60%	4.35%	392,896	371,543	(21,353)
33	478-10	DS Meters	4.37%	6.35%	613,804	891,912	278,108
34	482-10	GP (Frame) Structures	4.36%	6.44%	172,606	254,951	82,344
35	482-20	GP (Masonry) Structures	4.36%	2.21%	51,108	25,906	(25,202)
36	482-30	GP (Leased) Structures *	20.00%	14.00%	101,161	70,813	(30,348)
37	483-10	GP Computer Hardware	20.00%	20.00%	523,967	523,967	-
38	483-20	GP Computer Software - Systems	12.50%	12.50%	32,633	32,633	-
39	483-21	GP Computer Systems Software	20.00%	20.00%	-	-	-
40	483-22	GP Computer Software	20.00%	20.00%	10,265	10,265	-
41	483-30	GP Office Equipment	6.67%	6.67%	43,544	43,544	-
42	483-40	GP Furniture	5.00%	5.00%	21,457	21,457	-
43	484-00	GP Vehicles	17.88%	17.72%	1,063,138	1,053,625	(9,514)
44	485-10	GP Heavy Work Equipment	6.34%	5.91%	20,528	19,136	(1,392)
45	485-20	GP Heavy Mobile Equipment	7.35%	14.75%	93,152	186,938	93,786
46	486-00	GP Small Tools/Equipment	5.00%	5.00%	329,110	329,110	-
47	488-10	GP Telephone Equipment	6.67%	6.67%	38,744	38,727	(17)
48		Total Annual Depreciation			32,987,188	32,646,846	(340,343)
49							
50		Annual Composite Rate			2.6%	2.6%	
51							
	* Numbers above are in actual dollars with depreciation calculated using the January 1, 2012 gross asset values.						

Table 5.4-3: FEW - Impact of Implementing Recommended Depreciation Rates

Line #	Class	Description	Existing 2011 Rate	Recommended 2012 Rate	Depreciation Based on 2011 Rate	Depreciation Based on 2012 Rate	Increase + / Decrease -
1	401-01	Franchises and Consents	4.11%	4.33%	339	357	18
2	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	-	-	-
3	472-00	DS Structures	3.26%	3.37%	53	54	2
4	473-00	DS Services	1.94%	2.06%	78,226	83,065	4,839
5	474-00	DS Meters/Regulators Installations	3.33%	5.13%	47,671	73,439	25,768
6	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	-	-	-
7	475-00	DS Mains	1.51%	1.51%	136,395	136,395	-
8	477-10	DS Meas/Reg Additions	4.60%	3.86%	29,447	24,710	(4,737)
9	477-20	DS Telemetry	4.60%	3.72%	110	89	(21)
10	478-10	DS Meters	4.66%	6.46%	22,063	30,586	8,522
11	482-10	GP (Frame) Structures	4.41%	4.60%	760	793	33
12	482-20	GP (Masonry) Structures	4.41%	4.41%	1,103	1,103	-
13	482-30	GP (Leased) Structures *	10.00%	10.00%	-	-	-
14	483-10	GP Computer Hardware	20.00%	20.00%	-	-	-
15	483-30	GP Office Equipment	6.67%	6.67%	580	580	-
16	483-40	GP Furniture	5.00%	5.00%	-	-	-
17	484-00	GP Vehicles	16.01%	13.15%	27,427	22,527	(4,899)
18	485-10	GP Heavy Work Equipment	4.63%	3.18%	4,258	2,925	(1,334)
19	486-00	GP Small Tools/Equipment	5.00%	5.00%	8,877	8,877	-
20	488-10	GP Telephone Equipment	6.67%	6.67%	1,042	1,042	-
21		Total Annual Depreciation			358,349	386,540	28,191
22							
23		Annual Composite Rate			2.2%	2.4%	
24							
	* Numbers above are in actual dollars with depreciation calculated using the January 1, 2012 gross asset values.						

The asset categories that account for the majority of the forecast change in depreciation expense are Meters and Transmission Plant. Refer to page II-25 to II-31 of the Gannett Fleming study included in Appendix E-1 for further discussion.

For Meters, Gannett Fleming recommends a 20 year life, a decrease from the 25 years meter life recommended in the previous study. Implementation of more stringent metering testing guidelines introduced by Measurement Canada in 2010 will result in residential meters being retired by 20 years of age. Interviews with FEU Measurement staff and indications from metering experts across Canada confirm that residential meters will no longer be tested when they reach 15 to 20 years of age. The recommended shorter meter life results in an increase of approximately 2 percent in the depreciation rate for the Meter category.

For the 465-00 Transmission Plant – Pipeline category, in its previous study, Gannett Fleming recommended a 60 year life. A recent review of retirements, additions and other plant transactions for the period 1957 to 2009 suggests that an average service life of 65 years is more reflective of the historic retirement activity and consistent with the typical range of lives used for transmission mains in the gas industry. The recommended lengthening of the service life by 5 years leads to a slight decrease of approximately 0.2 percent in the depreciation rate.

Included in the current study also is a recommended change in how the asset category Distribution Systems Meters/Regulator Installations are accounted for and depreciated. Instead of relying on individual retirement of assets in this category which are wide and disparate, a simpler and still representative approach would be to follow an amortization approach, similar to the general plant categories outlined on page II-49 of the Gannett Fleming study included in Appendix E-1. Amortization accounting is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset to which it applies.

Under the revised approach, new plant additions to Distribution Systems Meters/Regulator Installations category would be recorded in a separate account (474.02) with depreciation expense calculated using a whole life rate. Gannett Fleming has recommended an initial whole life rate of 4.5 percent based on an expected life of 22 years. The existing meter install costs would remain in the current account (474.00) and continue depreciating at the recommended depreciation rate, which includes a factor for recovery of existing retirement losses. More details and information explaining the rationale for the proposed change is included in the Analysis of Asset Retirement Losses report contained in Appendix E-3.

The FEU believe the adoption of the depreciation rates as outlined in the current Depreciation Study is necessary in order to properly reflect the assets' useful lives and a fair allocation and recovery of depreciation expense between current and future ratepayers.

5.4.3 NEGATIVE SALVAGE

The Companies believe that estimates of negative salvage (removal costs less salvage proceeds) should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. This treatment recognizes that negative salvage is a cost of providing service and should be recovered from customers over the useful life of the asset. The inclusion of a provision for estimated negative salvage value in depreciation rates is consistent with the BCUC Uniform System of Accounts and is generally followed by other utilities across Canada. The BCUC Uniform System of Accounts states:

> *"There shall be charged monthly to account No. 303, "Depreciation", or other appropriate accounts with concurrent credits to the accounts for accumulated depreciation amounts which will allocate the service value for the plant over its estimated service life in a systematic and rational manner. The service value of the assets, for depreciation purposes, shall be their cost less their estimated net salvage value. Net salvage value means the salvage value less removal costs. The charges for depreciation shall be computed in conformity with the group system under the straight line method at rates approved by the Commission."*

In accordance with the direction provided in the Commission Orders referenced in Section 5.4.1, the FEU have included a report (included in Appendix E-2) that includes information on the following topics:

1. Treatment of negative salvage in generally accepted accounting principles;
2. Treatment of negative salvage in rate making in British Columbia, Canada, including by the National Energy Board, and the United States;
3. Options for collection of removal costs; and
4. Summary and recommendation.

As outlined in the report, the regulatory treatment that the FEU recommend is to follow the traditional approach[96] for regulatory assets that require significant removal costs, with funds segregated by asset classes in a separate liability account. In addition, the utilities will continue to review their regulatory assets to determine if any Asset Retirement Obligations ("AROs") are required to be recorded under GAAP. If AROs are required to be recorded for specific assets, the utilities propose to use the ARO methodology for regulatory purposes as well. At this time, no AROs have been identified for the Utilities.

The report demonstrates that the recommended treatment provides the best balance in achieving regulatory goals, in that it distributes costs to ratepayers equitably over time, improves utility accountability for removal costs collected from ratepayers through tracking funds separately by asset class, and ensures that funds for asset removal are available at the time they are needed, while achieving an appropriate balance with respect to administrative costs relating to implementation, maintenance and tracking.

For these reasons, the Companies have prepared their financial schedules incorporating this approach, recovering negative salvage over the lives of the applicable asset classes. The asset classes where negative salvage is included are shown in Table 5.4-4 below.

[96] Under this method, the negative salvage percentages are a component of depreciation rates, and are calculated as the expected cost to remove the asset today divided by the cost to install that asset originally.

Table 5.4-4: Negative Salvage Rates Recover Costs Over the Useful Lives of Assets

FortisBC Energy Utilities				
Estimates of Negative Salvage by Asset Class				
		FEI	FEVI	FEW
442.00	LNG Gas - Structures	-10%	-10%	n/a
443.00	LNG Gas - Equipment	-20%	-20%	n/a
449.00	LNG Gas - Other Equipment	-10%	-10%	n/a
462.00	Trans. Plant - Compressor Structures	-5%	-5%	n/a
463.00	Trans. Plant - Meas. & Reg. Structures	-5%	-5%	n/a
464.00	Trans. Plant - Other Structures	-5%	-5%	n/a
465.00	Trans. Plant - Trans. Pipeline	-10%	-10%	n/a
466.00	Trans. Plant - Compressor Equipment	-10%	-10%	n/a
467.10	Trans. Plant - Meas. & Reg. Equipment	-5%	-5%	n/a
468.00	Trans. Plant - Communications Equipment	-5%	-5%	n/a
472.00	Dist. Systems - Structures	-5%	-5%	-5%
473.00	Dist. Systems - Services	-50%	-50%	-50%
473.01	LILO - Dist. Systems - Services	-50%	n/a	n/a
474.00	House Regulators and Meter Installations	-10%	-10%	-10%
475.00	Dist. Systems - Mains	-20%	-20%	-20%
475.01	LILO - Dist. Systems - Mains	-20%	n/a	n/a
476.00	Dist. Systems - NGV Fuel Equipment	-20%	n/a	n/a
477.30	Dist. Systems - Meas. & Reg. Equipment	-5%	n/a	n/a
478.10	Dist. Systems - Meters	-5%	-5%	-5%

These negative salvage rates, the existing asset balances, and the calculations performed and described in the Depreciation Study result in the provisions for negative salvage as shown Sections 7.1 to 7.4 Schedule 61 and 62. The continuity of the negative salvage provision is discussed in detail in Section 6.1.5.4.

5.4.4 LOSSES ON DISPOSAL

Historically, the FEU have followed recognized regulatory group accounting procedures in accounting for their property plant and equipment. The FEU also adhere to the BCUC Uniform System of Accounts, unless modified by Commission order. Under both of these procedures, on retirement of depreciable gas plant, Accumulated Depreciation is charged with the ledger value of the gas plant retired and the cost of removal less amounts recovered for salvage and insurance. It is only in rare cases where the forces of retirement are outside of the forces that were contemplated in determining depreciation rates that gains and losses on depreciable plant would be recognized in income. Therefore, under historical practice, all normal course gains and losses on retirement of assets are included in accumulated depreciation.

This treatment is appropriate since group depreciation rates are set to recover the asset values over the average service life of the asset group, so that we expect some assets to be retired before their net book value reaches zero; others would be retired after their net book value reaches zero; and overall the gain/loss amount included in accumulated depreciation will have an immaterial value, with any material amounts recovered through changes to future depreciation rates. When depreciation rates are not adjusted to reflect the shorter service lives of assets, or retirements occur in a different pattern than was expected in the last accepted depreciation study, then the loss amount can build in accumulated depreciation.

An excerpt from the BCUC Uniform System of Accounts explains this more fully:

> *"The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group. It is not the intention of this classification to require the company to keep records of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated depreciation is subdivided according to the utility department to which applicable, or to each group of gas plant accounts. When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization."*

As indicated in the excerpts from the Negotiated Settlement Agreement for the Mainland and Vancouver Island included above, the size of the accumulated losses at December 31, 2009 ($149 million for the Mainland and $39 million for Vancouver Island) was of concern to the Commission Panel. Further analysis of these balances demonstrated that:

For FEI, four asset classes – 474 Regulators and Meter Installations, 478 Meters, 473 Services and 475 Mains account for $138 million or over 90 percent of the total accumulated loss of $149 million. Included in the $138 million is $54 million of actual removal costs incurred, leaving $84 million of actual losses. In accordance with the agreement reached in the 2010-2011 NSA, the analysis of the accumulated losses provided in Appendix E-3 has focused on these four asset classes.

For FEVI, further analysis determined that over 92 percent of the accumulated loss balance of $39 million was as a result of "disaggregation entries". These disaggregation entries resulted from an accounting system adjustment made on the purchase of Vancouver Island in 2003. At that time, the accumulated depreciation balances were transferred to the SAP accounting system as one amount for each asset class. Then, a program was run that calculated what the accumulated depreciation should have been given the current depreciation rates in the system and the age of the assets, and an entry was created to split the accumulated depreciation into two components – one to reflect the current remaining life of the existing assets, and the balance to the accumulated loss component. This calculation was done because historically Vancouver Island had never calculated losses on retirement and it was decided an estimation of the accumulated losses was required. As we have no ability to determine in hindsight the accuracy of this allocation, there is no further analysis that can be completed. Excluding these disaggregation entries and incurred removal costs of approximately $1.4 million, the accumulated loss balance at the end of 2009 would only be in the order of $1.6 million.

As demonstrated in the report included in Appendix E-3, the accumulated losses represent investments in utility plant required to continue providing service to customers, and have resulted from a number of factors, reflecting the environment that a natural gas utility operates in. In addition, and although not specifically addressed in the report included in Appendix E-3, a portion of the accumulated losses also results from inadequate recovery of depreciation from past customers. Adjustments to depreciation rates are required on a regular basis to reflect changes in the expected lives of assets. The past practice of deferring depreciation rate increases has contributed to losses being accumulated. Although the approval of previously recommended increases in depreciation rates would not have resulted in a material reduction in the balance of accumulated losses that existed at the end of 2009, they were designed to address the recovery of those losses over the expected lives of the assets.

Consistent with past practice, the depreciation rates included in the Depreciation Study filed with this Application include a portion related to the recovery of the unrecognized loss balances that were accumulated prior to 2010.

Net losses realized subsequent to 2009 have been recorded in a deferral account instead of in accumulated depreciation, as agreed to in the 2010-2011 Negotiated Settlement. As discussed in Section 6.3, the FEU propose to maintain this treatment for 2012 and 2013, and have proposed a 20 year amortization period for the deferral account that is aligned with the average service life of the asset categories that are contributing to the losses. This treatment will achieve the same result for ratepayers as the historical treatment followed by the Utilities and provided for in the BCUC Uniform System of Accounts.

5.4.5 AMORTIZATION OF CONTRIBUTIONS IN AID OF CONSTRUCTION ("CICA")

For FEI, the amortization rate of 2.89 percent for Distribution CIAC has been determined based on the average depreciation rate for the relevant distribution asset classes, namely, 473 Services, 474/478 Meters, and 475 Mains. The depreciation rate of 1.68 percent for Transmission CIAC has been determined based on the average depreciation rate for the relevant transmission asset classes, namely, 465 Pipe, 466 Compressor Equipment, and 467 Measuring, Regulating and Telemetry Equipment.

For FEVI, the average amortization rate for Distribution CIAC is 1.93 percent and for Transmission CIAC it is 1.79 percent, both of which have been determined based on the individual asset classes that the CIAC relate to. The Contribution for the Whistler pipeline is being amortized over 50 years.

For FEW, the average amortization rate is 1.67 percent.

5.4.6 SUMMARY OF DEPRECIATION AND AMORTIZATION

The FortisBC Energy Utilities have updated their recommendations for depreciation and amortization rates to reflect both their historical experience and their expectations for the service lives of their assets. The FEU have completed an analysis of the historical accumulation of losses in accumulated depreciation, and provided recommendations for the continued recovery of these losses through depreciation and amortization. The FEU have recommended a return to a traditional method of recovery of negative salvage, along with changes to the tracking and reporting of those amounts to allow for increased transparency. Overall, the FEU believe that the recommendations put forward are the most appropriate to allocate the recovery of prudent investment in capital from customers.

5.5 Other Revenue

5.5.1 INTRODUCTION TO OTHER REVENUE

Overall, as shown in Table 5.5-1 below, the Companies are forecasting a significant increase in other revenue in 2012 when compared to 2011 Approved, and a further modest increase in 2013.

Table 5.5-1: Forecast Other Revenue for 2012 and 2013[97]

($thousands) **Utility/Region**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 24,394	$ 27,203	$ 28,883
Vancouver Island	9,752	12,651	12,662
Whistler	56	16	16
Fort Nelson	60	24	24
Total	**$ 34,262**	**$ 39,894**	**$ 41,585**

[97] Section 7.1 to 7.4, Schedule 19 & 20

For all of the FortisBC Energy Utilities, other revenue includes revenue from service work (connection charges), late payment charges, and returned cheques. In addition, the Mainland utility receives revenue for wheeling charges (from Vancouver Island), third party revenue on its Southern Crossing Pipeline, and starting in 2012, revenue from natural gas vehicles service and biomethane recoveries. The Vancouver Island utility also receives revenue from the Mainland for LNG mitigation. Each of these categories is discussed below.

5.5.2 SERVICE WORK, LATE PAYMENT CHARGES AND RETURNED CHEQUES

For all of the Utilities, other revenue includes revenue for service work, late payment charges and returned cheques. Revenue from service work is $25 for customer additions and account transfers. Late Payment Charges are charged at a rate of 1.5 percent per month, and are estimated annually based on the prior year's experience. The 2012 and 2013 forecast Late Payment Charges have decreased in comparison to 2011 approved; this downward trend is consistent with the lower bad debt expense experienced by the Utilities. Annual returned cheque revenues are estimated at approximately 0.5 percent of the beginning of the year's account base, at a rate of $20 per cheque.

Mainland Other Recoveries of approximately $122 thousand in 2012 and $126 thousand in 2013 are from Non-Regulated Businesses related to recoveries of overhead under the Transfer Pricing policy (see Section 5.3.18).

The follow tables provide the 2012 and 2013 forecasts for each utility.

Table 5.5-2: Lower Late Payment Charges Forecast for Mainland

($thousands) **Mainland**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Late Payment Charges	$ 3,020	$ 2,333	$ 2,333
Connection Charges	2,907	2,662	2,685
NSF Returned Cheque Charges	82	79	79
Other Recoveries	76	122	126
Total	**$ 6,085**	**$ 5,196**	**$ 5,223**

Table 5.5-3: Lower Late Payment Charges Forecast for Vancouver Island

($thousands) **Vancouver Island**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Late Payment Charges	$ 345	$ 223	$ 224
Connection Charges	380	399	409
NSF Returned Cheque Charges	5	3	3
Other Recoveries	2	-	-
Total	**$ 732**	**$ 625**	**$ 636**

Table 5.5-4: Lower Late Payment Charges Forecast for Whistler

($thousands) **Whistler**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Late Payment Charges	$ 49	$ 11	$ 11
Connection Charges	5	4	4
NSF Returned Cheque Charges	-	-	-
Other Recoveries	2	1	1
Total	**$ 56**	**$ 16**	**$ 16**

Table 5.5-5: Lower Late Payment Charges Forecast for Fort Nelson

($thousands) **Fort Nelson**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Late Payment Charges	$ 38	$ 13	$ 13
Connection Charges	20	11	11
NSF Returned Cheque Charges	-	-	-
Other Recoveries	2	-	-
Total	**$ 60**	**$ 24**	**$ 24**

5.5.3 MAINLAND – VANCOUVER ISLAND WHEELING CHARGES

The Vancouver Island Wheeling Agreement, as approved by Commission Order No. G-149-07, is up for renewal at July 27, 2011. Under section 17.2 of the Wheeling Agreement, FEVI has the option to extend the term for 20 years with the demand rate for the first year of the renewal period determined in reference to the payment in the final year of the initial agreement.

FEVI will exercise its option to extend the agreement and there will be no changes to the determination of Wheeling Charges. Therefore, for the purposes of determining the 2012 and 2013 revenue requirements, FEI has calculated the Vancouver Island Wheeling Charge using the approved 2011 demand rate and has updated the other components of the charge in accordance with the initial agreement. 2011 revenue from FEVI wheeling charges was approximately $3.5 million and remains the same for the 2012 and 2013 forecast period.

5.5.4 MAINLAND - SOUTHERN CROSSING PIPELINE ("SCP") THIRD PARTY REVENUES

Similar to 2010 and 2011, SCP third party revenues are forecast at approximately $14.8 million for both 2012 and 2013. Table 5.5-6 below illustrates the SCP revenue forecast through 2013.

Table 5.5-6: Southern Crossing Pipeline Revenues Remain Consistent

($thousands) **SCP Revenue Component**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Northwest Natural Gas Co.	$ 8,849	$ 5,573	$ 5,573
MCRA	3,600	3,600	3,600
Motor Fuel Tax	(50)	(50)	(50)
Net Mitigation (T-South Enhanced Service)	2,400	5,703	5,703
Total SCP Revenues	**$ 14,799**	**$ 14,826**	**$ 14,826**

Historically, the SCP third party revenues have been allocated to customers through the MCRA and the delivery margin. The allocation methodology is intended to reflect the principle that customers paying for SCP in the delivery margin should share in the mitigation revenue associated with the SCP transportation resources. Recent changes in agreements necessitated a review and a change in this allocation, discussed further below. The net impact to SCP revenues of this change is zero because the allocation of additional costs associated with the Northwest Natural Gas Co. component is offset by the allocation of additional net mitigation revenues associated with the T-South Enhanced Service.

NORTHWEST NATURAL GAS CO.

The Company has a firm service contract with NWN, approved in Order No. G-98-05, for 46.5 MMcfd of SCP capacity over the period November 2004 through October 2020. Effective November 2010 the NWN payments increased from $7.3 million per year to about $9.0 million per year and PG&E Termination fees decreased from $825,000 per year to $145,000 per year.

The Company provides this firm transportation service to NWN from Yahk to Sumas via SCP capacity and Spectra Energy Kingsvale South Transportation. Currently, the cost of the 46.5 MMcfd Spectra Energy Kingsvale South capacity resides in the MCRA. The Company is proposing that the cost of the 46.5 MMcfd of Spectra Energy Kingsvale South capacity be offset against the NWN revenues which are credited to the Delivery Margin. The $3.3 million cost of holding Spectra Energy Kingsvale South capacity would be netted against the NWN revenues as the capacity is required in conjunction with the SCP capacity to facilitate deliveries to NWN, and the capacity is not available for use by the midstream to manage the Core load. Incorporating this change, the forecast NWN net revenues shown in Table 5.5-6 above for the 2012 and 2013 years are calculated as follows:

Table 5.5-7: 2012-2013 Calculation of Northwest Natural Gas Co. Revenue

	($thousands)
NWN Revenue	$ 8,994.0
PG&E Termination Fee	(145.0)
Spectra Transportation Tolls	(3,275.7)*
Net NWN Revenue	$ 5,573.3

* Forecast cost of Spectra Kingsvale South capacity.

FEI is proposing that the Spectra Energy Kingsvale South capacity charge be included in the Delivery Margin effective November 2011. The net NWN revenues in the 2011 year will then include the cost of the Spectra Transportation tolls for the two months of November and December and MCRA costs will be correspondingly reduced.

MCRA

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio.

Through Order No. G-141-09, the Commission approved the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2010 and 2011 settlement period. The Company continues to believe that this treatment of costs and revenues is fair and appropriate given that SCP capacity is an essential part of its midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers. In this Application, the Company seeks approval for the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2012 and 2013 forecast period. Consistent with the approach discussed above, the MCRA will continue to pay for the cost of their portion of the Spectra Energy Kingsvale South capacity.

NET MITIGATION REVENUE (T-SOUTH ENHANCED SERVICE)

In the SCP Revenue, the Company has included revenue associated with the T-South Enhanced Service which is forecast to be $5.7 million per year from 2011 through 2013.

The T-South Enhanced Service is an initiative between Spectra Energy and the Company that adds value to Spectra Energy's T-South service by providing shippers the option to access the Kingsgate market through the Company's interior transmission system and SCP. As a result of this initiative with Spectra Energy, the Company's customers will benefit from increased liquidity in the BC marketplace, decreased T-South tolls and incremental SCP mitigation revenue.

The initial term of the T-South Enhanced Service was May 1, 2010 to April 30, 2012. As a result of the success of this service, Spectra Energy and the Company executed an extension of the Service to October 31 2014 which was approved by the Commission in Order No. G-69-11 dated April 14, 2011.

Any variance from the forecast net mitigation revenues of $5.7 million will be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a five year period. Please refer to Section 6.3 for a discussion on this deferral account.

As discussed above, FEI is seeking approval in this Application for a change in the allocation between the delivery margin and midstream of the SCP costs and revenues, and of the Spectra Energy Kingsvale South charges related to the NWN capacity. As shown in Table 5.5-6 above, the net impact to the forecast annual SCP revenues for 2012 and 2013 of this change, as compared to the approved 2011 SCP revenues, is zero because the allocation of additional costs associated with NWN related Spectra Energy Kingsvale South capacity component is offset by the allocation of an additional $3.3 million in net mitigation revenues associated with the T-South Enhanced Service.

5.5.5 MAINLAND - NATURAL GAS FOR TRANSPORTATION SERVICE REVENUE

Natural Gas for Transportation Service is the compression and dispensing service for CNG fueling and transportation, delivery, fuel storage and dispensing service for LNG fueling. On December 1, 2010 FEI submitted its Application for Approval of a Service Agreement for CNG Service and for Approval of General Terms and Conditions for CNG and LNG Service (the “NGV Application”) to the Commission. On April 13, 2011, FEI submitted to the Commission and Interveners our Final Written Reply Submission. The forecasts made in relation to NGVs and NGV fueling infrastructure in the 2012-2013 RRA are premised on the assumption that the NGV Application will be approved as filed. Further, it is also based on the premise that the EEC incentives for NGV will continue. After the Commission’s Decision on the NGV Application has been issued, FEI will file an evidentiary update to this Application to the extent required to reflect the Commission’s determinations on these matters.

The other revenue forecast of $3.7 million in 2012 and $5.4 million in 2013 includes two components related to the NGV Application:

4. Fueling station revenue
5. Incremental delivery margin revenue

Table 5.5-8 outlines the components of other revenue associated with CNG and LNG Service included in the determination of the revenue requirements for 2012 and 2013.

Table 5.5-8: CNG and LNG Service Provide Benefits to All Customers in the Forecast Period

($thousands)	**2012**	**2013**
CNG Service Fueling Station Revenue	$ 699	$ 1,114
LNG Service Fueling Station Revenue	1,411	1,995
Total Fueling Station Revenue	2,110	3,109
CNG Service Delivery Margin Revenue	110	173
LNG Service Delivery Margin Revenue	1,527	2,122
Total Delivery Margin Revenue	1,636	2,295
Total CNG Service Revenue	809	1,287
Total LNG Service Revenue	2,937	4,116
Total CNG and LNG Service Revenue	**$ 3,746**	**$ 5,403**

The fueling station revenue is the recovery of the costs associated with the CNG and LNG fueling stations and reflects existing approved stations as well as expected additions of CNG and LNG Service fueling stations in 2012 and 2013.[98] We have forecast CNG Service fueling station revenue of $0.7 million in 2012 (from 5 stations) and $1.1 million in 2013 (from 8 stations). We have also forecast LNG Service fueling station revenue of $1.4 million in 2012 (from 2 stations) and $2.0 million in 2013 (from 3 stations). This results in a total fueling station revenue forecast of $2.1 million in 2012 and $3.1 million in 2013.

The incremental delivery margin revenue reflects the forecast volume on the delivery system that the CNG and LNG Service fueling stations are expected to provide (incremental volume from a total of 7 stations in 2012 and 11 stations in 2013). The volume is determined by Rate Schedules 6, 23, 25 and 16 and is forecast to provide incremental throughput on the delivery system of 517 TJs in 2012 and 742 TJs in 2013 (Table 5.5-9). The volume by rate schedule is multiplied by the existing delivery rate[99] to determine the forecast incremental delivery revenue of $1.6 million in 2012 and $2.3 million in 2013 that will benefit all existing non-bypass customers.

[98] The costs associated with all CNG and LNG contracts are embedded in the O&M and capital forecasts for 2012 and 2013. A comprehensive report on the Natural Gas for Transportation Service can be found in Appendix I.

[99] Corresponding existing delivery rate per Rate Schedule

Table 5.5-9: Forecast CNG and LNG Fueling Station Volume

Forecast Fueling Station Volume, TJ	2012	2013
CNG Service Volume	131	206
LNG Service Volume	386	536
Total CNG and LNG Service Volume	**517**	**742**

Additional information on the NGV Application, including the calculations behind the revenue forecasts, can be found in Appendix I.

5.5.6 MAINLAND BIOMETHANE RECOVERIES

The other revenue amounts of $62 thousand in 2012 and $29 thousand in 2013 represent the transfer of applicable biomethane costs from the delivery margin to the Biomethane Variance Account ("BVA"). This is the forecast cost of service each year associated with the upgrader plant. These costs are to be excluded from delivery rates and included in the Biomethane Energy Recovery Charge in accordance with Commission Order No. G-194-10. Please refer to the discussion on the BVA in Section 6.3, Rate Base Deferral Accounts, as well as the comprehensive Biomethane Report in Appendix J.

5.5.7 VANCOUVER ISLAND LNG MITIGATION REVENUES

LNG Mitigation Revenues commence in 2011 as a result of the Mt. Hayes LNG Facility becoming operational. These revenues reflect a storage and delivery agreement between the Vancouver Island and Mainland utilities for monthly demand charges of $1.0 million, or $12.0 million per year. The storage and delivery agreement was approved by Commission Order No. C-9-07.

5.5.8 SUMMARY OF OTHER REVENUE

The FortisBC Energy Utilities believe that the forecast amounts of other revenue for the years 2012 and 2013 reflect all applicable contracts and fixed revenues and are based on our best knowledge of the factors that drive the variable components.

5.6 Taxes

In carrying out its mandate as a gas service provider, the FortisBC Energy Utilities incur taxes that are imposed by different government bodies. The Companies manage these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the revenue requirement for each Company.

5.6.1 INCOME TAX

The FortisBC Energy Utilities are subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately include these costs in calculating the Companies' revenue requirements. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the corporate tax rate of 25.0 percent for 2012 and 2013. The corporate tax rates used in this RRA are based on the Canada Income Tax Act and the BC Income Tax Act substantively enacted legislation.

As approved by Commission Order No. G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

5.6.2 PROPERTY TAX

Property tax for 2012 and 2013 uses Company forecasts of assessed values of taxable assets, municipal mill rates, and taxes from revenues earned from natural gas consumed within the Municipalities. Property tax also includes the annual fee charged by the Oil & Gas Commission ("OGC"). The following table provides the forecast property tax expense for 2012 and 2013 for purposes of determining revenue requirement and rates for each of the FortisBC Energy Utilities.

Table 5.6-1: Property Tax Expense by Utility/Region[100]

($ thousands) **Utility / Region**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 49,556.5	$ 48,858.0	$ 49,656.5	$ 51,239.0
Vancouver Island	9,751.6	9,292.1	9,895.0	10,262.5
Whistler	264.6	269.3	236.2	244.2
Fort Nelson	167.7	165.8	172.4	178.0
Total Property Taxes	**$ 59,740.4**	**$ 58,585.2**	**$ 59,960.0**	**$ 61,923.7**

The Mainland, Whistler and Fort Nelson regions maintain Commission approved deferral account mechanisms to track variances between forecast and actual property tax expense. Please refer to Section 6.2 for a discussion of the Property Tax Variance Accounts. For Vancouver Island, the variances flow through the RSDA.

The following subsections provide details on the property tax forecasts for each Utility.

[100] Section 7.1 to 7.4, Schedule 25 & 26

5.6.2.1 Mainland Property Tax Expense

Table 5.6-2 below provides the property tax forecast for the Mainland.

Table 5.6-2: Forecast Mainland Property Tax Expense

($ thousands) Asset Type	Approved 2011	Projected 2011	Forecast 2012	Forecast 2013
Distribution Assets	$ 17,459.5	$ 16,539.6	$ 17,889.3	$ 18,842.8
Transmission Assets	13,300.3	13,309.6	14,035.3	14,485.9
Gas Storage Assets	848.4	942.0	987.5	1,033.9
Manufactured Gas Assets	27.1	25.8	27.0	28.3
General Assets	2,791.4	2,681.9	2,804.4	2,935.3
Revenue and Other Taxes	15,129.8	15,359.1	13,912.8	13,912.8
Total Property Taxes	**$ 49,556.5**	**$ 48,858.0**	**$ 49,656.5**	**$ 51,239.0**

Mainland property taxes are forecast to be $698.5 thousand (1.4 percent) lower than originally approved for 2011. 2012 property taxes are forecast to increase by $798.5 thousand (1.6 percent) compared to projected 2011 and 2013 property taxes are forecast to increase by $1.58 million (3.2 percent) compared to forecast 2012 based on the following:

1. Distribution Assets

   2011: 2011 Taxes are projected to be lower than 2011 Approved due to lower forecast tax rates.

   2012: Comparing the 2012 Forecast to 2011 projected property taxes, additions are expected to add $400 thousand in taxes, with the remaining $950 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

   2013: In 2013, additions are expected to add $400 thousand in taxes, with the remaining $554 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission, Gas Storage, Manufactured Gas and General Assets

   For 2011 to 2013 taxes on transmission, gas storage, manufactured gas and general assets are forecast to increase as a result of inflationary pressures from materials and labour on legislated pipeline rates, in addition to increases in general and other tax rates.

3. Revenue and other taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. For all municipalities except the City of Vancouver, FEI pays a tax of 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010. For the City of Vancouver, FEI pays 1.25 percent of revenues earned in the preceding year. For example, taxes payable to the City of Vancouver in 2012 will reflect revenues earned in 2011.

   2011 and 2012 taxes payable are based on actual reporting. 2012 taxes payable are forecast to decline by an average of 11.7 percent, while 2013 taxes are forecast to remain unchanged from 2012 levels.

5.6.2.2 Vancouver Island Property Tax Forecast

Table 5.6-3 below provides the property tax forecast for Vancouver Island.

Table 5.6-3: Forecast Vancouver Island Property Tax Expense

($ thousands) **Asset Type**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets	$ 4,750.6	$ 4,426.7	$ 4,715.6	$ 4,968.1
Transmission Assets	2,513.6	2,472.8	2,601.9	2,686.7
Gas Storage Assets	483.6	507.6	620.6	634.7
General Assets	215.6	152.4	359.1	375.1
Revenue and Other Taxes	1,788.2	1,732.6	1,597.9	1,597.9
Total Property Taxes	**$ 9,751.6**	**$ 9,292.1**	**$ 9,895.0**	**$ 10,262.5**

Vancouver Island property taxes are forecast to be $459.5 thousand (4.7 percent) lower than approved for 2011. 2012 property taxes are forecast to increase by $602.9 thousand (6.5 percent) compared to projected 2011 and 2013 property taxes are forecast to increase by $367.5 thousand (3.7 percent) compared to forecast 2012 based on the following:

1. Distribution Assets

   2011: 2011 Taxes are expected to be lower than 2011 Approved due to lower forecast tax rates.

   2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $103 thousand in taxes, with the remaining $185.7 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2013: In 2013, additions are expected to add $105.2 thousand in taxes, with the remaining $147.3 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission

2011 projected taxes are expected to be lower than originally forecast because of lower expected tax rates. For 2012 to 2013, taxes on transmission assets are forecast to increase as a result of inflationary pressures from materials and labour on legislated pipeline rates, in addition to increases in general and other tax rates.

3. Gas Storage

The projected 2011 taxes are expected to be higher than 2011 Approved due to tax rates.

In 2012, completion of the Mt. Hayes LNG facility in 2011 will result in full taxation of this facility adding $99.3 thousand in taxes. Increases in tax rates results in an additional $13.7 thousand in taxes.

In 2013, taxes are expected to increase by $14.1 thousand due to general inflation on assessment values and tax rates.

4. General Assets

General assets are mainly comprised of office buildings. In 2011, taxes for general assets are projected to be lower than originally forecast as it was originally expected the Langford regional operations centre would become taxable to FEVI in 2011, however, the purchase is not expected to complete until April 2011.

For 2012, this property is forecast to be fully taxable resulting in increased property taxes of $182.6 thousand. General forecast property value increases and higher tax rates result in an additional $24.1 thousand in property taxes.

In 2013, taxes are forecast to increase by $16.0 thousand due to overall property value inflation and higher general and other tax rates.

5. Revenue and other taxes

A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. For all municipalities FEVI pays 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

2011 taxes payable are based on actual reporting. 2012 taxes payable used preliminary estimates of actual data, which indicated an average decrease of 7.8 percent in reported revenues. 2013 taxes are based on a zero increase on 2010 revenues.

5.6.2.3 Whistler Property Tax Forecast

Table 5.6-4 below provides the property tax forecast for Whistler.

Table 5.6-4: Forecast Whistler Property Tax Expense

($ thousands) **Asset Type**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets	$ 117.8	$ 108.8	$ 115.9	$ 123.8
Transmission Assets	-	-	-	-
Gas Storage Assets	-	-	-	-
Manufactured Gas Assets	-	-	-	-
General Assets	-	-	-	-
Revenue and Other Taxes	146.9	160.5	120.3	120.3
Total Property Taxes	**$ 264.6**	**$ 269.3**	**$ 236.2**	**$ 244.2**

Whistler property taxes are forecast to be $4.7 thousand (1.8 percent) higher than originally approved for 2011. 2012 property taxes are forecast to decrease by $33.1 thousand (12.3 percent) when compared to projected 2011 and 2013 property taxes are forecast to increase by $8.0 thousand (3.4 percent) compared to forecast 2012 based on the following:

1. Distribution Assets

   2011: 2011 Taxes are expected to be lower than 2011 Approved due a successful appeal in 2011 resulting in lower assessment values.

   2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $2.5 thousand in taxes, with the remaining $4.6 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

   2013: In 2013, additions are expected to add $2.6 thousand in taxes, with the remaining $5.3 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Revenue and Other taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. Whistler revenues are calculated based on 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

   2011 and 2012 taxes payable are based on actual reporting. 2013 taxes are based on a zero increase to 2010 revenues.

5.6.2.4 Fort Nelson Property Tax Forecast

Table 5.6-5 below provides the property tax forecast for Fort Nelson.

Table 5.6-5: Forecast Fort Nelson Property Tax Expense

($ thousands) **Asset Type**	**Approved 2011**	**Projected 2011**	**Forecast 2012**	**Forecast 2013**
Distribution Assets	$ 94.9	$ 92.1	$ 99.5	$ 104.4
Transmission Assets	0.3	0.3	1.3	1.3
Gas Storage Assets	-	-	-	-
Manufactured Gas Assets	-	-	-	-
General Assets	12.5	13.5	14.2	14.9
Revenue and Other Taxes	60.0	60.0	57.4	57.4
Total Property Taxes	**$ 167.7**	**$ 165.8**	**$ 172.4**	**$ 178.0**

Fort Nelson property taxes are forecast to be $1.9 thousand (1.1 percent) lower than originally approved for 2011. 2012 property taxes are forecast to increase by $6.5 thousand (3.9 percent) when compared to projected 2011 and 2013 property taxes are forecast to increase by $5.6 thousand (3.2 percent) when compared to forecast 2012 based on the following:

1. Distribution Assets

   2011: 2011 Taxes are expected to be lower than 2011 Approved due lower forecast tax rates.

   2012: Comparing 2012 Forecast to 2011 projected property taxes, additions are expected to add $2.5 thousand in taxes, with the remaining $4.9 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2013: In 2013, additions are expected to add $2.5 thousand in taxes, with the remaining $2.4 thousand resulting from inflation on distribution pipeline rates, as well as increases in general and other tax rates.

2. Transmission Assets

   The Muskwa River Crossing Project is forecast to add $1.0 thousand in 2012.

3. General Assets

   General assets are mainly comprised of the Fort Nelson office, taxes on which are forecast to increase by general inflation.

4. Revenue and Other Taxes

   A portion of a utility company's property taxes payable within a municipality on certain improvements are calculated based on revenues earned within that municipality. Fort Nelson revenues are calculated based on 1 percent of revenues earned in the second preceding year. For example, taxes payable in 2012 will reflect revenues earned in 2010.

   Revenues from gas consumed within Fort Nelson (Northern Rockies Regional Municipality[101]) are expected to decrease by 4.5 percent in 2012 based on actual reported 2010 revenues. For 2013, revenues are forecast to remain unchanged.

5.6.3 CARBON TAX

The Carbon Tax represents a cost to the Companies on their own consumption of fuel to operate compressors, line heaters, motor vehicles and space heating. The Carbon Tax rate applicable to natural gas effective July 1, 2011 is $1.24 per GJ, and will rise to $1.49 per GJ on July 1, 2012. There are no further announced increases beyond this date. The estimated costs to the FortisBC Energy Utilities with respect to Carbon Tax on own-use fuel are embedded in O&M and capital. If the Carbon Tax rate is adjusted during the period of the RRA from what is currently enacted, the impact will be assessed and reflected in the Tax Variance Deferral Accounts.

[101] Northern Rockies Regional Municipality was created with the amalgamation of The Town of Fort Nelson and the Northern Rockies Regional District on February 6, 2009

5.6.4 HARMONIZED SALES TAX

In July of 2009, the Governments of Canada and British Columbia announced that the Harmonized Sales Tax ("HST") would be implemented in British Columbia effective July 1, 2010, replacing the BC Social Service Tax ("SST") and the Goods and Services Tax ("GST"). The B.C. HST is a federally administered commodity tax eligible on goods and services at a rate of 12 percent, representing a federal component of 5 percent and a BC provincial component of 7 percent. Businesses are entitled to claim Input Tax Credits ("ITCs") on HST paid. However, large businesses will have their ITCs restricted during the first 8 years of HST implementation. Accordingly, ITCs for the provincial portion of HST (7 percent) are restricted for most telecommunication expenses, passenger vehicles, heat and electricity, and meals and entertainment expenses. The Companies are entitled to recover the HST paid on taxable purchases of goods and services, therefore, other than the above noted restricted ITCs, the tax does not represent a net cost to the Companies.

In an Application filed with the BCUC on September 27, 2010, the FortisBC Energy Utilities proposed that the 2010 and 2011 revenue requirement impacts of the implementation of HST be recorded in the applicable Tax Variance Deferral Accounts and returned to customers as part of the 2012 Revenue Requirements filings. Please see Section 6.2 Deferred Charges for a discussion on the additions to the Tax Variance Deferral Account and the corresponding amounts returned to customers through this Application.

A referendum on the continuation of the HST will be held in British Columbia on June 24, 2011. Although the referendum is non-binding, the BC government has pledged that if a simple majority of 50 percent vote against the HST, the tax will be repealed. The RRA assumes continuation of the HST; should the HST be repealed or an alternate tax introduced, the impact on revenue requirements, including any associated implementation costs, will be assessed and reflected in the Tax Variance Deferral Accounts.

5.6.5 MOTOR FUEL TAX ("MFT") AND INNOVATIVE CLEAN ENERGY ("ICE") LEVY

The Province levies other taxes on various goods and services. These taxes include the MFT, which applies at a rate of 1.9 cents per 810.32 litres of natural gas used in compressors. The ICE levy of 0.4 percent on purchases of energy including electricity and natural gas was eliminated effective July 1, 2010. The MFT is not recoverable and therefore represents a net cost to the Companies.

5.6.6 TAX ISSUES

5.6.6.1 Risk of Changes in Tax Laws or Accepted Assessing Practices

At any time, the Companies can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Federal or Provincial sales taxes or any other tax that may be imposed. As discussed in Section 6.2, the Mainland, Whistler and Fort Nelson utilities will continue the approved deferral account treatment to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies, at Federal, Provincial, Municipal or any other level of jurisdiction. In particular and for greater certainty, should the Companies' tax treatment of removal costs (see Section 5.6.6.2 below) be challenged by the Canada Revenue Agency, the tax variance deferral account will capture such reassessments.

5.6.6.2 Tax Benefits Relating to Prior Periods – Removal Costs

During 2010, the Companies conducted a review of the tax treatment of removal costs to determine whether all or a component of these costs could be deducted for tax purposes in the year incurred. The Companies have determined that it is reasonable to deduct these costs in the year incurred for income tax purposes because of the nature of the costs classified as 'removal costs' for accounting purposes. Historically, including for the determination of rates in 2010 and 2011, the Companies have added these costs to Undepreciated Capital Cost ("UCC") for tax purposes. Beginning with the year ended December 31, 2010, the Companies have deducted removal costs for tax return filing purposes. The Companies have deferred the tax benefits relating to the 2010 tax deduction and will do the same for 2011. The analysis to support the deduction of these benefits was not completed in time to include them in rates for 2010 and 2011. A discussion of the amount of the benefits, and other items captured in the Tax Variance deferral accounts is included in Section 6.3. In the 2012 and 2013 Utility tax calculations, removal costs have been deducted in determining income tax expense.

5.6.7 CONCLUSION

The FortisBC Energy Utilities will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies. The Companies manage these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this RRA reflect the current substantively enacted tax legislation and have been properly calculated and applied in calculating the revenue requirement for each Company.

5.7 Financing Costs and Return on Equity

The cost of service includes both financing costs and a return on equity. The Utilities' financing costs are determined by the percentage of debt included in the capital structure, and the cost of that debt. The total percentage of debt is determined by the Commission, and the allocation between long-term and short-term debt is managed by the Utilities. The Utilities' return on equity is determined by the amount of equity included in the capital structure (the equity percentage) and the allowed return on equity, both determined by the Commission.

In this section, we will explain what the allowed debt and equity percentages are for each of the utilities, and the anticipated debt issuances and expected interest rates that the Companies have included in the forecasts for 2012 and 2013. The impacts of these forecasts have been appropriately included in the Companies' revenue requirements.

This section (see Section 5.7.2) also explains why the Companies are seeking Commission's permission to defer the filing of evidence with respect to FEVI and FEW's equity component as directed in Directive No. 7 of Commission Order G-158-09. As discussed in this section, given FEU's plans to file an application in Fall 2011 to Amalgamate the Companies, FEU believes that it is more efficient to defer the filing of the evidence until that time.

5.7.1 FINANCING COSTS

Financing costs included in this RRA reflect the anticipated debt issuances and retirements over the forecast period, as well as the interest expense that has been calculated based on existing interest rates for existing debt, and external forecasts of interest rates for new debt issues. Debt consists of both Long-term Debt and Short-term (Unfunded) Debt.

5.7.1.1 Short-term Debt

FEI obtains short term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the issuance of commercial paper by maintaining a $500 million committed credit facility, which matures August 2013. FEVI obtains its short term funding through advances made available on its $300 million committed credit facility. The credit facilities provide the Companies with crucial liquidity should there be constraints in the capital markets that make obtaining cost-effective financing for working capital and debt issuance requirements temporarily unavailable. FEW obtains its financing from FHI.

5.7.1.2 Long-term Debt

FEI is a public issuer and issues long-term debt by way of a shelf prospectus. FEVI has issued long-term debt by way of private placement in the past. FEW's long-term debt consists of an intercompany loan from its parent FHI. Fort Nelson receives an allocation of FEI's long-term debt.

FEI does not have any long-term debt due for redemption in 2012 or 2013, but expects to issue $100 million in medium term note debentures in July of 2011 and has reflected this issue in its long term debt projection.

In 2013 FEVI has forecast a $15.5 million retirement of the Pacific Coast Energy Pipeline Agreement ("PCEPA") revolving credit facility, which matures in January 2013. The PCEPA facility is available solely for the purpose of funding prepayments of the Government of Canada and Government of BC contributions. The non-interest bearing contributions from the Federal and Provincial governments were in connection with the construction and operation of the Vancouver Island natural gas pipeline, of which $49.1 million is forecast to be outstanding at year-end 2011, drawn down to $25.0 million by year-end 2013.[102] These contributions are shown as CICA. Any annual prepayments of the Government contributions are funded with debt and equity in the same proportion as the capital structure of Vancouver Island. The repayment of the PCEPA facility and also the refinancing of the 2013 contributions will be financed through short-term debt as the amounts come due, with a long-term debt issue planned for after 2013.

FEW has not forecast any long-term debt issuances or redemptions in 2012 or 2013.

5.7.1.3 Forecast of Interest Rates for 2012 and 2013

The Companies use interest rate forecasts to estimate future interest expense. Forecasts of Prime rate and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for new issues of long-term debt. The forecasts are averages of projections made by leading economists at four Canadian Chartered banks. Credit spreads on new long-term debt are based on current indicative rates.

Short-term rates (i.e. Prime bank lending rate) are projected to increase in the coming months. Surveys of leading economists expect the Prime bank lending rate to remain on average at 3.63 percent for 2011, and then increase to 5.56 percent by 2013.[103] The Companies' short-term borrowing rate forecast for 2012 and 2013 is based on the historical short-term borrowing differential between the Prime bank lending rate and the rate issued under the commercial paper program at that time. The short-term interest rate forecasts for all Companies are shown in Table 5.7-1 and Table 5.7-2 below.

[102] Section 7.2, Schedule 84
[103] Economist reports are included in Appendix C-1

Table 5.7-1: Determination of Short-Term Interest Rates for 2012

2012 Interest Rate Forecast %				
	Mainland	**Vancouver Island**	**Whistler**	**Fort Nelson**
Prime Rate	4.57%	4.57%	4.57%	4.57%
Short-Term Debt Rate Spread	-1.82%	-0.32%	-0.82%	-1.82%
Short-Term Debt Rate	2.75%	4.25%	3.75%	2.75%

Table 5.7-2: Determination of Short-Term Interest Rates for 2013

2013 Interest Rate Forecast %				
	Mainland	**Vancouver Island**	**Whistler**	**Fort Nelson**
Prime Rate	5.56%	5.56%	5.56%	5.56%
Short-Term Debt Rate Spread	-1.81%	-0.31%	-0.81%	-1.81%
Short-Term Debt Rate	3.75%	5.25%	4.75%	3.75%

Due to the uncertainty associated with forecasting interest rates, the Mainland, Whistler and Fort Nelson utilities have an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the timing of long-term debt issues, as compared to forecast.

5.7.1.4 Interest Expense Forecast

The interest expense forecast reflects the Utilities' existing and projected borrowing costs on long term debt and projected short-term debt.

The calculation for short-term interest expense is determined by applying the short-term debt rate to the short-term debt balance. Long-term debt interest expense is determined using the effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The long-term debt schedules for each company can be found in Sections 7.1 to 7.4, Schedule 82 to 84.

The following tables highlight long-term and short-term interest expense for 2012 and 2013.

Table 5.7-3: Forecast 2012 Interest Expense[104]

2012 Forecast					
($ thousands) **Interest Expense**	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Short Term	1,644	4,556	198	7	6,405
Long Term	106,548	21,003	1,022	343	128,916
Total Interest Expense	**108,192**	**25,559**	**1,220**	**350**	**135,321**

Table 5.7-4: Forecast 2013 Interest Expense[105]

2013 Forecast					
($ thousands) **Interest Expense**	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Short Term	3,393	7,268	233	13	10,907
Long Term	106,730	20,473	1,022	346	128,571
Total Interest Expense	**110,123**	**27,741**	**1,255**	**359**	**139,478**

5.7.2 ALLOWED CAPITAL STRUCTURE AND RETURN ON EQUITY

On December 16, 2009, the Commission released Order No. G-158-09 and its accompanying decision on "*Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Return on Equity and Capital Structure Application".* The decision established the deemed capital structure for each utility, discontinued the use of the automatic adjustment mechanism, and fixed an allowed return on equity for all three utilities. For purposes of determining the revenue requirements for 2012 and 2013, the 2012 and 2013 capital structure and return on equity for each of the Companies will remain as currently approved through BCUC Order No. G-158-09. Below, the Companies have set out the deemed capital structure and allowed ROE used in the calculation of the 2012 and 2013 revenue requirements, and explain their rationale for deferring a request for filing evidence on the equity component of capital structure for FEVI and FEW.

5.7.2.1 Background

The capital structure and return on common equity ("ROE") for FEU is established by the Commission for use in the calculation of rates. For many years, the Commission annually set the ROE for utilities in British Columbia based on the Benchmark ROE for FEI using a formula that ties the utilities' rates of return on equity to the forecast yield on long-term Canada (30

[104] Section 7.1 to 7.4, Schedule 80
[105] Section 7.1 to 7.4, Schedule 81

years) bonds for the forthcoming year. This formula is commonly referred to as the Automatic Adjustment Mechanism ("AAM").

On May 15, 2009 FortisBC Energy Utilities applied to the BCUC to request:

1. that the Commission eliminate the use of AAM in the determination of the ROE;
2. a review and adjustment to the Benchmark ROE and FEI's equity thickness for rate-setting purposes and that the so determined ROE for FEI be used in establishing the ROE of FEVI and FEW used for rate setting.

By Order No. G-158-9 dated December 16, 2009, the Commission agreed that the appropriate equity ratio for FEI is 40 percent and approved an ROE for FEI of 9.50 percent for rate setting purposes. The Commission decision also set the FEI ROE as the Benchmark in establishing the return on equity and set FEW and FEVI's allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 50 basis points for both utilities.

Table 5.7-5 provides the current deemed capital structure and return on equity applicable to each utility:

Table 5.7-5: Capital Structure and Return on Equity

Utility/Region	Debt	Common Equity	Return on Equity
Mainland	60%	40%	9.50%
Vancouver Island			10.00%
Whistler			10.00%
Fort Nelson			9.50%

The currently approved deemed capital structures and return on equity for each utility is used in the determination of the revenue requirements for 2012 and 2013, as well as the combined cost of service for 2013.

5.7.2.2 FEVI and FEW Capital Structures

As neither FEVI nor FEW applied for a change in their respective capital structures in 2009, the Commission confirmed their existing capital structures and directed them to file evidence as to what equity component best reflects their respective long term risks in their next Revenue Requirement Application.[106]:

[106] BCUC Order No. G-158-09, Directive 7.

> *"TGVI and TGW are to file in their respective next revenue requirement applications evidence on the equity component that best reflects their respective long-term business risks."*

In consideration of FEU's intention to file an application later this year seeking amalgamation of FEVI, FEW and FEI, the Companies believe that it is not appropriate to address the issue at this time. The Companies are requesting, for the purposes of regulatory efficiency, leave to defer filing evidence for the capital structures of FEVI and FEW until the Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011. The following discussion addresses the mentioned Commission directive and reasons for this request.

As outlined in Section 1.2.5, it is the Companies' intention to file an application in the Fall 2011 seeking approval to amalgamate FEI, FEVI and FEW, and move to a harmonized rate structure. If amalgamation and rate harmonization is approved, FEVI and FEW will cease to exist; if amalgamation and rate harmonization is not granted, FEVI and FEW will continue as separate stand alone utilities. As the Fall application will determine the future of FEVI and FEW, the Companies believe that it is appropriate for regulatory efficiency purposes to defer submission of evidence relating to their respective stand-alone equity components at this time.

Under the Companies' proposal, in the Fall application the Companies would provide:

- Evidence with respect to the equity ratio for FEVI and FEW on stand-alone basis. (The evidence would be provided to meet the Commission's directive. It is currently expected that the Companies still would not seek at that time any change for the stand-alone FEVI and FEW capital structures, as that would be based on the assumption that amalgamation will not proceed. In the event that Amalgamation is not approved, FEVI and FEW will apply for changes to their equity component in their next respective revenue requirement based on the evidence filed.)
- Evidence on the impact of amalgamation on appropriate capital structure and ROE for the amalgamated utility, all else being equal. (Note that this would take the form of a change *relative to* the existing benchmark, and not a change *to* the benchmark itself. The current benchmark, based on the pre-amalgamation FEI as the benchmark low risk utility, can remain in place until the next comprehensive cost of capital proceeding.)

This approach is efficient for two reasons.

First, the capital structure of a regulated utility is a function of the business risks facing the entity. There is overlap with respect to the long term business risks for both the amalgamated entity and FEVI / FEW, and addressing that evidence at the same time will eliminate the potential for redundant inquiries. In the 2009 *Return on Equity and Capital Structure*

Application, FEI explained the business risks faced by FEI in detail and recognized the following key drivers for the risk associated with operating earnings[107]:

- Provincial climate change and energy policies has increased the risk inherent to FEIs core natural gas business;
- Natural gas' competitive position relative to electricity has weakened;
- FEI is capturing a smaller percentage of new constructions;
- Electricity is increasingly the choice of high-density housing;
- Alternative energy sources further weaken FEI's competitive position,
- Fuel switching has also diminished demand for natural gas.

These same risks also face FEVI and FEW, and will impact their appropriate capital structure and return on equity. In addition to the reasons outlined above, FEVI and FEW face additional risks arising from, but not limited to, their price disadvantage, smaller size, lower market penetration rates and higher supply disruption risk[108]. In light of what is involved in assessing business risk, there is considerable potential for redundancy if business risk is addressed both in this proceeding and in the Fall 2011 proceeding.

Second, a determination on a change (if the evidence supports a change) to the equity component of FEVI and / or FEW is only required in the event that the amalgamation is not approved. If the issue is deferred until the Fall Amalgamation and Rate Design Phase 'A' Application, depending on the Commission's determination about amalgamation, it may be unnecessary for the Commission to ever determine the appropriate capital structure for the stand alone FEVI and FEW. Therefore, undertaking a full review of FEVI / FEW at this time is in the Companies' view inefficient.

In sum, the Companies seek permission to defer filing evidence of FEVI and FEW's capital structure to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011. For the purposes of determining the revenue requirements, the 2012 and 2013 capital structure and return on equity for each of the companies has been calculated as currently approved through BCUC Order No. G-158-09.

5.7.3 FINANCING COSTS AND RETURN ON EQUITY CONCLUSION

The FortisBC Energy Utilities continue to prudently manage their capital structure and address financing requirements. The Companies maintain adequate credit facilities to provide sufficient

[107] FEU (formerly Terasen Utilities) 2009 ROE and Capital Structure Application, Section 4, page 24.
[108] FEU (formerly the Terasen Utilities) 2009 ROE and Capital Structure Application Panel IR 1.6 Response.

liquidity to meet their ongoing working capital requirements and address any concerns that may result from tighter credit markets. The Companies are active participants in the debt capital markets and have fostered strong relationships with its lenders. We have taken a reasoned approach to funding our long term debt requirements. With this Application, the Utilities are not seeking a change to either their capital structure or ROE.

6 RATE BASE

The determination of rate base is a significant step in the calculation of the revenue requirement; it forms the basis for the earned return component of the cost of service. The rate base is comprised of:

- mid-year net plant in-service (gross plant in service, less contribution in aid of construction, less accumulated depreciation relating to both, and negative salvage), adjusted for the timing of completion of major capital projects;
- work-in-progress not attracting allowance for funds used during construction;
- the mid-year balance of unamortized deferral accounts (regulatory assets and liabilities);
- the thirteen-month average of cash working capital and other working capital;
- mid-year future income tax asset and offsetting liability; and
- in the case of the Mainland, the LILO benefit arising from LILO agreements with several Interior municipalities.

The following subsections will discuss in detail the various components of rate base, beginning with an overview of rate base and a summary by utility/region (Section 6.1) that is followed by discussions on capital expenditures (Section 6.2) and rate base deferral accounts (Section 6.3).

6.1 Rate Base Overview and Summary by Utility/Region

The 2012 and 2013 rate base amounts, as determined in Sections 7.1 to 7.4, Schedules 40 and 41 of this RRA, represent the average investment by the Companies in utility assets necessary to provide service to our customers. The table below sets out the forecast rate base for 2012 and 2013, for each FortisBC Energy Utility.

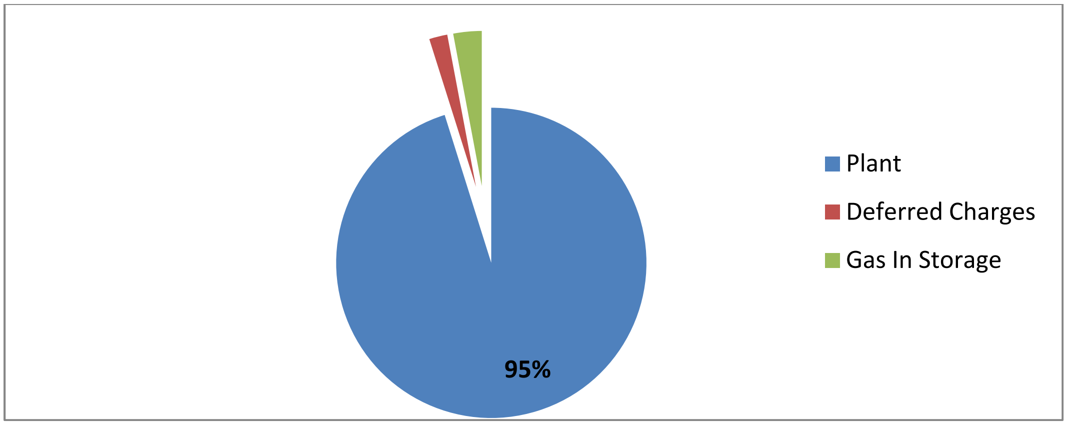
Table 6.1-1: Rate Base in 2012 and 2013 is Growing[109]

($ thousands) **Utility/Region**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mainland	$ 2,629,185	$ 2,736,507	$ 2,788,327
Vancouver Island	728,993	787,864	814,078
Whistler	42,594	42,139	41,502
Fort Nelson	6,839	8,889	9,127
	$ 3,407,611	**$ 3,575,399**	**$ 3,653,034**

[109] Section 7.1 to 7.4, Schedules 40 and 41

The total FEU rate base of $3.6 billion is comprised largely of net gas plant in service as shown in Figure 6.1-2:

Figure 6.1-1: FEU Rate Base is Primarily Net Gas Plant in Service



The following subsections provide a discussion on the various components of rate base for each Utility.

6.1.1 MAINLAND RATE BASE SUMMARY

The table below sets out the Mainland rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

Table 6.1-2: Mainland Rate Base 2011 through 2013[110]

($ thousands) **Mainland**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mid Year Net Plant In Service	$ 2,494,713	$ 2,555,445	$ 2,634,300
Adjustment to 13-month average	-	40,567	-
Work in progress, no AFUDC	15,627	17,110	17,110
	2,510,340	2,613,122	2,651,410
Deferred Charges	6,770	27,407	38,574
Cash Working Capital	(6,534)	(3,445)	(1,963)
Gas In Storage Working Capital	114,804	97,294	97,242
Other Working Capital	5,287	3,611	4,380
Other	(1,482)	(1,482)	(1,316)
Utility Rate Base	**$ 2,629,185**	**$ 2,736,507**	**$ 2,788,327**

110 Section 7.1, Schedules 40 and 41

The growth in rate base for the forecast period is largely attributable to investments in system sustainment and reliability and the addition of assets (both capital and deferral) related to the CCE Project being in service starting in 2012. Offsetting these increases are reductions in Gas In Storage due primarily to lower commodity rates. Driving the increase in the 2013 deferred charges is the growth in the balance of the EEC deferral account and the full amortization of credit balances in several of the Non-Controllable deferral accounts in 2012. Please refer to Section 6.3 for a discussion on the forecast deferred charges balances.

6.1.2 VANCOUVER ISLAND RATE BASE SUMMARY

The table below sets out the Vancouver Island rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

Table 6.1-3: Increase in Vancouver Island Rate Base is Driven by Mount Hayes LNG[111]

($ thousands) **Vancouver Island**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mid Year Net Plant In Service	$ 651,454	$ 774,128	$ 796,990
Adjustment to 13-month average	56,712	1,210	-
Work in progress, no AFUDC	3,608	2,285	2,285
	711,774	777,623	799,275
Deferred Charges	4,908	(1,096)	3,891
Cash Working Capital	134	295	476
Gas In Storage Working Capital	11,146	10,605	10,605
Other Working Capital	1,031	437	(169)
Other	-	-	-
Utility Rate Base	**$ 728,993**	**$ 787,864**	**$ 814,078**

The growth in the 2012 rate base is generally attributable to the full year impact of the Mount Hayes LNG Facility. Balances in the GCVA and EEC deferral accounts are the significant contributors to changes in the mid-year balance of deferred charges included in rate base. Please refer to Section 6.3 for a discussion on the forecast deferred charges balances.

6.1.3 WHISTLER RATE BASE SUMMARY

The table below sets out the Whistler rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

[111] Section 7.2, Schedules 40 and 41

Table 6.1-4: Amortization of the Pipeline Contribution Decreases Whistler's Rate Base[112]

($ thousands) Whistler	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 12,643	$ 13,746	$ 14,080
Adjustment to 13-month average	-	111	-
Work in progress, no AFUDC	63	23	23
	12,706	13,880	14,103
Deferred Charges	29,176	27,584	26,703
Cash Working Capital	31	42	61
Gas In Storage Working Capital	655	628	625
Other Working Capital	26	5	10
Other	-	-	-
Utility Rate Base	**$ 42,594**	**$ 42,139**	**$ 41,502**

The annual amortization of the Whistler Pipeline Contribution results in a slight decline to the Whistler rate base each year. As discussed in Section 6.3, the Whistler Pipeline Contribution has been decreased by approximately $2.5 million reflecting a reduction in the estimate of the final Pipeline costs; however, this reduction is offset by additions in 2012 and 2013 related to the CCE Project as well as other plant additions.

6.1.4 FORT NELSON RATE BASE SUMMARY

The table below sets out the Fort Nelson rate base for 2012 and 2013, for purposes of determining rates and revenue requirements.

[112] Section 7.3, Schedules 40 and 41

Table 6.1-5: Increases in Fort Nelson Rate Base Due to Muskwa River Crossing[113]

($ thousands) Fort Nelson	Approved 2011	Forecast 2012	Forecast 2013
Mid Year Net Plant In Service	$ 7,256	$ 8,823	$ 9,028
Adjustment to 13-month average	(666)	-	-
Work in progress, no AFUDC	38	-	-
	6,628	8,823	9,028
Deferred Charges	154	54	83
Cash Working Capital	54	8	12
Gas In Storage Working Capital	-	-	-
Other Working Capital	3	4	4
Other	-	-	-
Utility Rate Base	**$ 6,839**	**$ 8,889**	**$ 9,127**

The growth in the 2012 rate base is attributable to the full year impact of the Muskwa River Crossing Project. The projected in-service date of the assets related to the Project is November 1, 2011 with total project costs currently estimated at $3.0 million (excluding AFUDC), unchanged from the amount approved by Commission Order No. G-27-11.

6.1.5 NET PLANT IN SERVICE ("NPIS")

The mid-year NPIS balances reflect the necessary additions to ensure that the Utilities are able to meet the needs of our customers. The mid-year NPIS is the largest component of rate base and is the sum of the averages of the gross plant in-service (including intangible plant), CIAC, accumulated depreciation, and negative salvage.

6.1.5.1 Gross Plant in Service ("GPIS")

The ending GPIS balances are made up of opening GPIS plus plant additions, both regular and CPCNs, less retirements. Plant additions are comprised of capital expenditures plus overheads capitalized, plus AFUDC, and adjusted for opening and closing work-in-progress ("WIP"). Details of capital expenditures are discussed in Section 6.2. Retirements are forecast as a percentage of additions each year. The percentage used is based on a five year historical average for all classes except those subject to amortization accounting. For asset classes subject to amortization accounting, retirements are forecast based on the year that the asset becomes fully amortized.

The mid-year gross plant in service is as follows:

[113] Section 7.4, Schedules 40 and 41

Table 6.1-6: Approved and Forecast Gross Plant in Service Balances

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 3,495,886	$ 3,656,234	$ 3,837,558
Vancouver Island	1,155,525	1,290,340	1,330,943
Whistler	16,225	16,710	17,420
Fort Nelson	10,458	12,162	12,722
Total	**$ 4,678,093**	**$ 4,975,445**	**$ 5,198,643**

The forecast gross plant in service additions for the Utilities for 2012 and 2013 are as follows:

Table 6.1-7: Mainland Gross Plant in Service Additions[114]

Mainland, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 133,971	$ 130,811
Overhead Capitalized	31,375	33,106
AFUDC and WIP Adjustments	5,128	4,629
Subtotal: Regular Capital Additions	170,473	168,546
Special Projects & CPCN Additions	82,393	-
Total Plant Additions	$ 252,867	$ 168,546

Table 6.1-8: Vancouver Island Gross Plant in Service Additions[115]

Vancouver Island, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 29,950	$ 29,079
Overhead Capitalized	4,933	4,967
AFUDC and WIP Adjustments	139	147
Subtotal: Regular Capital Additions	35,022	34,193
Special Projects & CPCN Additions	21,973	-
Total Plant Additions	$ 56,996	$ 34,193

[114] Section 7.1, Schedule 42
[115] Section 7.2, Schedule 42

Table 6.1-9: Whistler Gross Plant in Service Additions[116]

Whistler, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 719	$ 480
Overhead Capitalized	127	128
AFUDC and WIP Adjustments	-	-
Subtotal: Regular Capital Additions	846	608
Special Projects & CPCN Additions	221	-
Total Plant Additions	$ 1,066	$ 608

Table 6.1-10: Fort Nelson Gross Plant in Service Additions[117]

Fort Nelson, $ thousands	Forecast 2012	Forecast 2013
Regular Capital Expenditures	$ 609	$ 276
Overhead Capitalized	120	125
AFUDC and WIP Adjustments	-	-
Subtotal: Regular Capital Additions	729	400
Special Projects & CPCN Additions	-	-
Total Plant Additions	$ 729	$ 400

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

The AFUDC rate applied to work in progress is based on the Company's after tax weighted average cost of capital ("WACC").[118] The WACC for each Company is based on its current approved capital structure and is determined as follows:

Figure 6.1-2: After Tax Weighted Average Cost of Capital Formula

(ROE x Equity Thickness) + [(Long Term Debt Rate x Long Term Debt Thickness) + (Short Term Debt Rate x Short Term Debt Thickness)] x (1- Tax Rate)

The approved AFUDC Rates for 2011 and the forecast AFUDC rates for 2012 and 2013 are shown in Table 6.1-11.

[116] Section 7.3, Schedule 42
[117] Section 7.4, Schedule 42
[118] The AFUDC rate also applies to non-rate base deferral accounts

Table 6.1-11: Forecast AFUDC Rates for 2012 and 2013

Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	6.83%	6.77%	6.76%
Vancouver Island	6.63%	6.44%	6.56%
Whistler	6.26%	6.17%	6.27%

The AFUDC charged to work in progress is calculated by multiplying the project costs by the company's AFUDC rate. Table 6.1-12 below shows the 2011 approved and 2012 and 2013 forecast AFUDC by utility.

Table 6.1-12: Approved and Forecast AFUDC

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 5,051	$ -	$ -
Vancouver Island	3,703	604	-
Whistler	-	-	-
Fort Nelson	-	-	-
	$ 8,754	**$ 604**	**$ -**

6.1.5.2 Contributions in Aid of Construction (CIAC)

Gross CIAC is composed of opening contributions, plus additions, and less the retirements throughout the year. The year-end CIAC amounts reflect forecast contributions associated with main extensions, excess service line charges, billable alterations, hazard mitigation work chargeable to customers, and system damage. The Utilities do not forecast retirements for CIAC, except for software tax savings which are retired based on the year that they become fully amortized and in the case of Vancouver Island, retirements related to the government loans. The CIAC in the Vancouver Island rate base includes government loan retirements of $20 million in 2012 and $4.1 million in 2013, bringing the outstanding balance of the government loans to $29.1 million at the end of 2012 and $25.0 million at the end of 2013. The closing balance of CIAC in Vancouver Island also includes the contribution from Whistler to Vancouver Island for the Whistler pipeline of $14.6 million. Forecast additions to CIAC are discussed in Section 6.2.6.

The year-end CIAC amounts are forecast as follows:

Table 6.1-13: The Year End Balance of CIAC Decreases Rate Base[119]

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ (194,753)	$ (183,107)	$ (189,803)
Vancouver Island	(276,176)	(254,306)	(250,614)
Whistler	(96)	(186)	(186)
Fort Nelson	(1,271)	(1,287)	(1,287)
Total	**$ (472,296)**	**$ (438,886)**	**$ (441,890)**

6.1.5.3 Accumulated Depreciation

The rate base of the Utilities includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation and amortization expense, and decreased through retirements. A discussion on the depreciation policies for the Utilities is included in Section 5.4. In addition, the accumulated depreciation balances reflect depreciation expense calculated using the depreciation rates as recommended by the updated Depreciation Study and the opening 2012 accumulated depreciation balances have been adjusted to reflect the transfer of estimated negative salvage opening balances to the negative salvage provision.

The mid-year accumulated depreciation is as follows:

Table 6.1-14: Forecast Accumulated Depreciation Reflects Updated Depreciation Study and Negative Salvage Transfers[120]

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ (860,508)	$ (966,678)	$ (1,059,824)
Vancouver Island	(285,125)	(302,515)	(332,731)
Whistler	(3,496)	(2,761)	(3,067)
Fort Nelson	(2,486)	(2,542)	(2,897)
Total	**$ (1,151,615)**	**$ (1,274,495)**	**$ (1,398,518)**

6.1.5.4 Negative Salvage

As discussed in Section 5.4.3, the rate base of the Utilities includes both an opening and closing balance for negative salvage. The continuity of negative salvage (see Sections 7.1 to 7.4, Schedule 61 and 62) is described further below.

119 Section 7.1 to 7.4, Schedules 63-65
120 Section 7.1 to 7.4, Schedules 54-60

OPENING BALANCE

The opening balance is transferred from accumulated depreciation and determined by calculating the December 31, 2009 negative salvage provision as follows:

1. Increases in provision equal to the negative salvage component of depreciation rates multiplied by the applicable year's opening gross plant balance for those asset classes and years this treatment was approved (asset classes 474 and 478 in FEI starting in 2004; asset classes 462, 463, 465, 466, 467, 472, 473, 474, 475, 477, 478, 482, 484, 485 in FEVI starting in 2003);
2. Decreases in provision equal to the actual removal costs less salvage incurred in each of those years.

ADDITIONS

Additions represent the provisions for negative salvage as calculated using the estimated negative salvage rates provided in Table 5.4-4 and determined through the Depreciation Study included as Appendix E-1. The provision is included as a line item on the cost of service schedule and is added back for purposes of calculating income tax expense (Sections 7.1 to 7.4, Schedules 33 to 35).

COSTS INCURRED

These are the estimates of actual costs to be incurred for removal. These are the costs deducted in calculating income tax expense.[121]

Retirement costs are incurred in all major gas asset categories including mains, services, meters and stations. The following table summarizes historical and forecast expenditures required to support ongoing recurring retirement work in these gas asset categories.

Table 6.1-15: Approved, Actual and Forecast Retirement Expenditures

Utility/Region, ($ thousands)	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 11,290	$ 12,609	$ 12,932
Vancouver Island	344	632	648
Whistler	5	6	6
Fort Nelson	-	-	-
	$ 11,639	$ 13,247	$ 13,586

The types of retirement activities that occur are described separately below:

[121] Section 7.1 to 7.4, Schedules 33 to 35

- Retired or abandoned main is generally company driven and is the removal or deactivation of an existing main from plant at the direction of the asset owner due to age, redundancy, leaking beyond economical repair or insufficient capacity.
- Retired services can be removed for the same reasons and also consist of both customer driven and company driven programs. Customer driven service retirements or removals are initiated by homeowners and developers as older homes are demolished, existing property lots are subdivided and new properties and potential homes are created. A developer typically purchases an older group of homes, requests cut-off or removal of the gas services, demolishes the homes, and rebuilds more single family or multi-family units with multiple additional service lines or service header main with multiple meters.
- Company driven service retirements or removals are driven by our inactive services program. An inactive service to a premise is a live gas service with no meter with no existing customer; these assets continue to attract regular maintenance but are not used for gas delivery. Inactive services are often forgotten by the property owner and represent a significant risk of third party damage if not removed.
- Inactive service stubs are another segment of service retirements. These are stubs installed at the time of main installation and or service lines cut-off at the property line for a variety of reasons. Their existence increases the probability of third party damage as they are difficult to locate using electronic instruments and project outside the mechanical no-dig zone of the main to which they are attached (i.e. the mechanical no-dig zone is one metre on each side of the main). If there is no future use expected for these stubs after a period of time our policy is to cut-off the service at the main to eliminate potential for third party damage.
- Retired meters (and meter removals) expenditures are for the removal and retirement of an existing meter from a premise due to age, malfunction, obsolescence or inactivity. The level of activity is driven primarily by the residential meter exchange activity as residential meters are typically removed from service once they have reached the end of their useful life in contrast to larger meter sets which may undergo some meter shop maintenance and are re-circulated for service. Inactive meters are typically those pulled from service due to customer inactivity after an appropriate time period.
- Miscellaneous retirements would include all other gas asset categories but are generally expenditures related to retiring or removing stations.

The forecast expenditures for 2012-2013 for miscellaneous and mains retirements are generally project specific whereas the forecast for meters and services is generally recurring annual work that is expected to remain fairly consistent from 2010 actuals.

CLOSING BALANCE

Calculated as the opening balance plus additions less costs incurred. The closing balance is deducted from rate base on Sections 7.1 to 7.4, Schedules 40 and 41.

As discussed in Section 5.4, the FortisBC Energy Utilities believe that the proposed treatment is in the best long-term interests of customers and is the most appropriate for rate making purposes.

The mid-year negative salvage included in rate base for 2012 and 2013 is as follows:

Table 6.1-16: Mid-Year Balance of Negative Salvage[122]

($ thousands) Utility/Region	Forecast 2012	Forecast 2013
Mainland	$ (6,200)	$ (9,900)
Vancouver Island	(10,835)	(14,175)
Whistler	(37)	(112)
Fort Nelson	-	-
Total	**$ (17,071)**	**$ (24,187)**

6.1.6 13-MONTH ADJUSTMENT

Since the NPIS is calculated on a mid-year basis (beginning plus ending divided by two), for large capital projects, the rate base is adjusted to reflect the timing of when these projects actually go into rate base. In 2012, a 13-month adjustment has been applied to Mainland, Vancouver Island and Whistler to include the assets associated with the CCE Project as of January, 2012. For the Mainland, the 13-month adjustment also accounts for the Tilbury Land purchase which enters rate base January 1, 2012. For Vancouver Island, the 13-month adjustment also accounts for the Victoria Regional Office CPCN in-service as of October 2012. The Companies have not forecast any 13-month adjustments in 2013.

6.1.7 WORK IN PROGRESS INCLUDED IN RATE BASE

Consistent with past practice, Work in Progress included in rate base represents construction work in progress for projects that are shorter than three months in duration and less than $50 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project. The Work in Progress (not attracting AFUDC) included in Rate Base has been forecast at the ending 2010 balance for both 2012 and 2013.

[122] Section 7.1 to 7.4, Schedules 61 and 62

6.1.8 RATE BASE DEFERRAL ACCOUNTS

The forecast mid-year balance of deferral accounts has been included in rate base. Individual rate base deferral accounts are discussed in Section 6.3.

6.1.9 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital. Cash working capital is defined as the average amount of capital provided by investors in the Companies to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. Other working capital includes Gas-In Storage, transmission line pack, inventory and construction advances.

6.1.9.1 Cash Working Capital

The cash working capital requirements that have been included in this RRA appropriately reflect the most recent Lead Lag Study results and represent the amounts required to compensate the Utilities for the timing differences between when expenditures are required to provide service and when collections are received for that service.

As a result of the implementation of HST, the Utilities have removed the GST and PST lead days from the cash working capital calculation and updated them to show an HST lead day and a Residential Energy Credit lead day as shown in Table 6.1-17 below. The modification of the lead days to reflect HST does not materially impact the cash working capital or the cost of service for each utility and results in a minor decrease to the cash working capital because of the higher input tax credit associated with gas purchases and non-labour O&M.

Table 6.1-17: The Implementation of HST Results in a Minor Change to Cash Working Capital

	Approved GST Lead Days	Proposed HST Lead Days	Residential Energy Credit Adjustment	Proposed REC Lead Days
Mainland	38.8	38.8	(5.0)	33.8
Vancouver Island	39.8	39.8	(5.0)	34.8
Whistler	39.8	39.8	(5.0)	34.8
Fort Nelson	38.8	38.8	(5.0)	33.8

Consistent with the treatment of GST, HST is remitted to the Government of Canada at the end of the subsequent month. Therefore, the current lead day associated with GST is applicable when determining the working capital implications of the HST. HST of 12 percent is collected from non-residential customers while residential customers receive the Residential Energy Credit ("REC"). The REC is typically received from the Province five days before the HST is remitted to The Government of Canada.

As discussed in Section 5.6, the implementation of the HST replaced the GST, PST and also eliminated the ICE Levy. The impact of the ICE Levy was embedded in the lead day determined for PST. Therefore, the GST and PST lead days are no longer applicable to the determination of cash working capital and must be removed.

The Utilities request approval to modify their approved Lead Lag days with the removal of the GST and PST lead days and the insertion of the proposed HST and REC lead days, as set out in Table 6.3-17.

6.1.9.2 Gas-in-Storage and Other Working Capital

The main component of other working capital is gas-in-storage inventory, which is determined on a 13-month average basis. The forecast amount of Gas in Storage is subject to significant risk, both in terms of forecasting volumes that will be held in storage, and in terms of forecasting future commodity prices. For purposes of this RRA, the forecast volumes and prices are consistent with the assumptions used in forecasting the gas costs and the balances of the gas cost deferral accounts.

The forecast balances of the gas-in-storage component of working capital are provided in the table below:

Table 6.1-18: Gas in Storage Balances Reflect Current Commodity Forecasts[123]

($ thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 114,804	$ 97,294	$ 97,242
Vancouver Island	11,146	10,605	10,605
Whistler	655	628	625
Fort Nelson	-	-	-
Total	**$ 126,605**	**$ 108,527**	**$ 108,472**

6.1.10 SUMMARY

Mainland, Vancouver Island, Whistler and Fort Nelson must be accorded the opportunity to earn a return on their investments in rate base. The rate base amounts that have been forecast for 2012 and 2013 incorporate required expenditures to meet the expectations of our growing customer base, support the repatriated customer service function and to make improvements related to system integrity and reliability.

[123] Section 7.1 to 7.4, Schedules 72 to 74

6.2 Capital Expenditures

6.2.1 INTRODUCTION

The Companies' capital expenditures involve small and large projects of many types that are required to meet increasing regulatory requirements and public expectations to maintain the safety, reliability and integrity of the distribution and transmission facilities used to provide service to existing and new customers, respond to the information needs and inquiries of customers, and to provide the information and systems necessary to support the business.

The FortisBC Energy Utilities forecast 2012 and 2013 capital expenditures (excluding Allowance for Funds Used During Construction ("AFUDC") and CPCN projects) are as outlined in the tables below. A summary of the Companies' capital expenditures for the 2010/2011 period with a comparison to the Approved amounts over the same period is also provided below. To better reflect and describe the nature of the capital expenditures, the categories of expenditures have been redefined from Category A, B and C used in past applications to Sustainment Capital, Growth Capital, and Other.

- Sustainment Capital – Includes expenditures for meter recall or meter exchange programs (previously Category A – Replacement Meters); system reinforcements to the distribution and transmission systems to maintain capacity to meet existing and forecast load, and replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability (previously Category B – Transmission and Distribution); and expenditures for mains and service renewals and alterations (previously Category C – Non IT Distribution)
- Growth Capital – Includes expenditures for the installation of new mains, services and meters (previously Category A – New Mains, Services and Meters) and NGV and biomethane equipment
- Other Capital – Includes expenditures for Facilities, Equipment and IT (previously Category C – IT and Non IT Facilities/Equipment)

This categorization has been used in the tables that follow, showing the total capital expenditures for each of the Mainland, Vancouver Island, Whistler and Fort Nelson utilities.

Table 6.2-1: Approved, Actual and Forecast Mainland Capital Expenditures[124]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	18,178	19,126	19,055	19,525	20,668	21,272
Transmission System Reinforcements / Integrity and Reliabililty	9,546	9,771	8,663	8,663	20,350	24,386
Distribution System Reinforcements / Integrity and Reliabililty	7,900	5,198	6,250	6,750	7,170	7,610
Distribution Mains and Service Renewals and Alterations	10,060	11,342	9,810	11,370	17,330	21,845
	45,684	**45,437**	**43,778**	**46,308**	**65,517**	**75,114**
Growth Capital						
New Customer Mains	8,807	4,538	9,306	5,738	6,124	6,497
New Customer Services	14,722	13,874	15,940	11,175	12,044	12,903
New Customer Meters	1,588	1,905	1,728	1,782	1,965	2,105
Biomethane/NGV				7,004	7,078	7,378
	25,117	**20,317**	**26,974**	**25,699**	**27,211**	**28,883**
Other						
Equipment	3,497	3,434	3,363	2,664	3,310	2,930
Facilities	3,213	4,177	3,483	4,138	8,424	4,124
IT	16,000	12,418	16,000	16,000	18,000	18,000
	22,710	**20,029**	**22,845**	**22,802**	**29,734**	**25,054**
Subtotal	**93,511**	**85,783**	**93,597**	**94,809**	**122,462**	**129,051**
Contributions in Aid of Construction						
	(4,024)	**(3,922)**	**(3,929)**	**(6,227)**	**(5,341)**	**(5,399)**
Total Regular Capital	**89,487**	**81,861**	**89,669**	**88,582**	**117,121**	**123,652**

[124] Section 7.1, Schedule 42

Table 6.2-2: Approved, Actual and Forecast Vancouver Island Capital Expenditures[125]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	1,492	1,134	1,496	1,188	1,215	1,250
Transmission System Reinforcements / Integrity and Reliabililty	5,045	3,836	7,868	7,868	8,098	6,328
Distribution System Reinforcements / Integrity and Reliabililty	1,520	991	2,315	2,315	2,685	935
Distribution Mains and Service Renewals and Alterations	1,000	1,156	1,000	1,326	4,276	5,646
	9,057	**7,117**	**12,679**	**12,697**	**16,274**	**14,159**
Growth Capital						
New Customer Mains	2,725	1,836	2,966	2,553	2,757	2,922
New Customer Services	5,940	5,309	6,459	4,517	4,926	5,270
New Customer Meters	540	430	582	440	480	513
	9,206	**7,575**	**10,006**	**7,510**	**8,163**	**8,705**
Other						
Equipment	1,615	1,181	1,500	1,391	3,073	3,591
Facilities	291	400	141	343	439	616
IT	1,500	1,473	1,500	1,500	2,000	2,000
	3,406	**3,054**	**3,142**	**3,234**	**5,512**	**6,207**
Subtotal	**21,669**	**17,746**	**25,827**	**23,441**	**29,948**	**29,070**
Contributions in Aid of Construction						
	(442)	**(371)**	**(448)**	**(487)**	**(426)**	**(431)**
Total Regular Capital	**21,226**	**17,374**	**25,379**	**22,953**	**29,523**	**28,639**

125 Section 7.2, Schedule 42

Table 6.2-3: Approved, Actual and Forecast Whistler Capital Expenditures[126]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	27	44	27	41	41	42
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	10	45	-	-	-	-
Distribution Mains and Service Renewals and Alterations	82	27	84	94	88	81
	120	**116**	**111**	**134**	**129**	**123**
Growth Capital						
New Customer Mains	51	219	35	218	223	227
New Customer Services	97	122	68	48	52	53
New Customer Meters	14	3	9	4	5	5
	163	**344**	**112**	**270**	**279**	**285**
Other						
Equipment	18	5	17	17	20	60
Facilities	53	15	25	25	290	13
IT	-	-	-	-	-	-
	71	**20**	**42**	**42**	**310**	**73**
Subtotal	**353**	**480**	**265**	**446**	**718**	**481**
Contributions in Aid of Construction						
	-	**(5)**	**-**	**-**	**-**	**-**
Total Regular Capital	**353**	**475**	**265**	**446**	**718**	**481**

[126] Section 7.3, Schedule 42

Table 6.2-4: Approved, Actual and Forecast Fort Nelson Capital Expenditures[127]

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	3	3	2	2	2	2
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	729	325	2,711	2,661	340	160
Distribution Mains and Service Renewals and Alterations	69	17	63	63	63	33
	801	**345**	**2,776**	**2,726**	**405**	**195**
Growth Capital						
New Customer Mains	11	23	11	11	12	12
New Customer Services	22	32	13	48	47	53
New Customer Meters	4	10	5	6	6	6
	37	**65**	**29**	**65**	**65**	**71**
Other						
Equipment	-	-	8	8	10	10
Facilities	-	-	-	-	129	-
IT	-	-	-	-	-	-
	-	**-**	**8**	**8**	**139**	**10**
Subtotal	**838**	**410**	**2,813**	**2,799**	**609**	**276**
Contributions in Aid of Construction						
	-	**-**	**-**	**-**	**-**	**-**
Total Regular Capital	**838**	**410**	**2,813**	**2,799**	**609**	**276**

A discussion of each of the Sustainment Capital, Growth Capital, Equipment and Facilities, IT, and CIAC categories follows. The FEU have also provided a discussion of both current and forecast CPCN projects that are not included in the table above, but that enter rate base in the year that they go into service.

For historical information for each of the Companies please refer to Appendix D.

6.2.2 SUSTAINMENT CAPITAL EXPENDITURES

6.2.2.1 Overview of Sustainment Capital

The expenditures within sustainment capital include gas system improvements to ensure adequate capacity to the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system. These expenditures mitigate the risk of loss from system outages and business interruptions.

[127] Section 7.4, Schedule 42

Before discussing the 2012 and 2013 forecast expenditures, the following will provide background on the planning for transmission and distribution system reinforcements and for safety, reliability and integrity of the systems.

SYSTEM REINFORCEMENT PLANNING

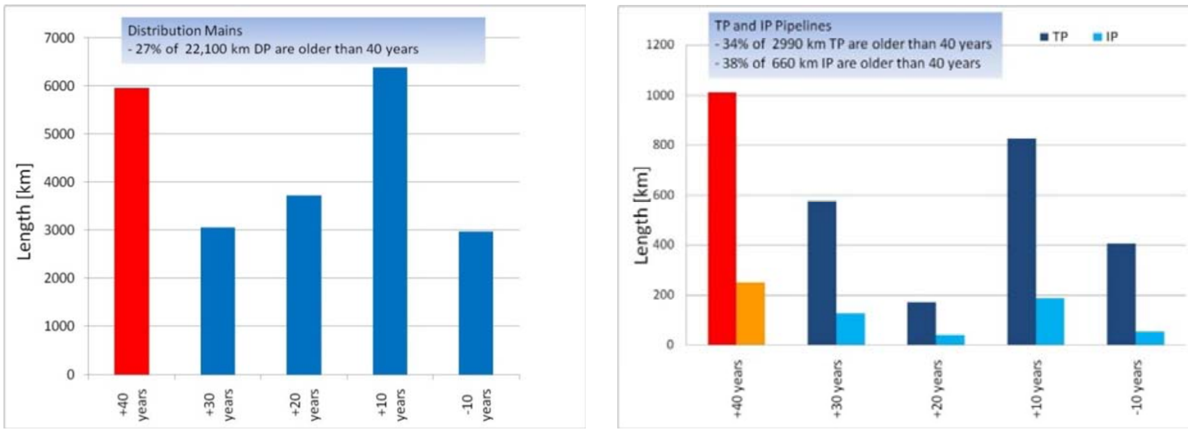
The requirements for transmission system capacity reinforcements are identified and evaluated annually through system hydraulic and financial analyses with the best overall alternative selected in a long term system capacity plan (typically for a 20 year planning period). The analyses are based on long term demand forecasts, accounting for the hourly demand variations of heat sensitive load, the amount of line pack available within the transmission system, and any midstream gas supply benefits. Long range planning for the transmission system is necessary to account for the long lead times for typical large infrastructure projects (i.e. regulatory approvals, public consultation, conceptual design, detailed engineering, and construction schedules). The plan optimizes the transmission capacity additions to meet the forecast demand from core market (residential, commercial, small industrial) customers under design temperature conditions and firm transportation from industrial customers.

Similarly, for distribution, the key tool used to determine the capital requirements necessary for these facilities is the Companies' five-year infrastructure plan. This plan is developed using a detailed network analysis process that incorporates the needs of each community with different weather patterns, growth rates, geographic location, and specific customer attributes, and is updated annually. The planning cycle starts with gathering pressure information from hundreds of points throughout the system, which are then adjusted for weather differences. This data is then used to validate and adjust the hydraulic modeling application, ensuring that the model continues to accurately reflect the operating conditions of the natural gas delivery system, Computer programs are used to analyze the flows on gas distribution grids and the transmission system to model growth and to develop a plan that minimizes the long-term costs of meeting customer needs while meeting appropriate codes and standards. As well, other components of the system (such as gate stations, odorant facilities, metering, etc.) are reviewed and analyzed to ensure the design delivery requirements will continue to be met. Once the network analysis of the distribution system is complete, specific projects to meet the load growth are determined, evaluated and prioritized. The evaluation is centered on ensuring that undue risk is not taken with regard to meeting peak day obligations or compromising system integrity. Where possible, procedures such as active monitoring and manual intervention are examined as a way to analyze the impacts of deferring the requirement for projects without risking the security of supply to the customers. The final output of the review is the five-year capacity upgrade plan which is then used to create a portion of the five-year budget.

AGING INFRASTRUCTURE AND ASSET RISKS

Most Utilities in North America, including FEU, are facing the challenge of aging infrastructure. Today, FEU is responsible for gas transmission and distribution assets with a book value of approximately $3.0 billion, and an approximate replacement value of $6.8 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines (Figure 6.2-1) have been in service for 40 to 55 years. These aging assets will be facing an increasing rate of deterioration and be approaching the end of their service life leading to the need for replacement starting within the next 10 years.

Figure 6.2-1: Proportions of Transmission and Distribution Approaching Retirement

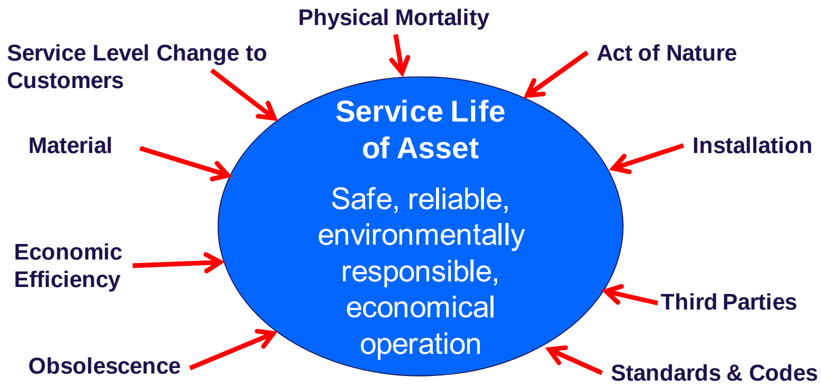


Distribution Main Age **Transmission and Intermediate Pressure Pipe Age**

(+10 years means more than / -10 years means less than)

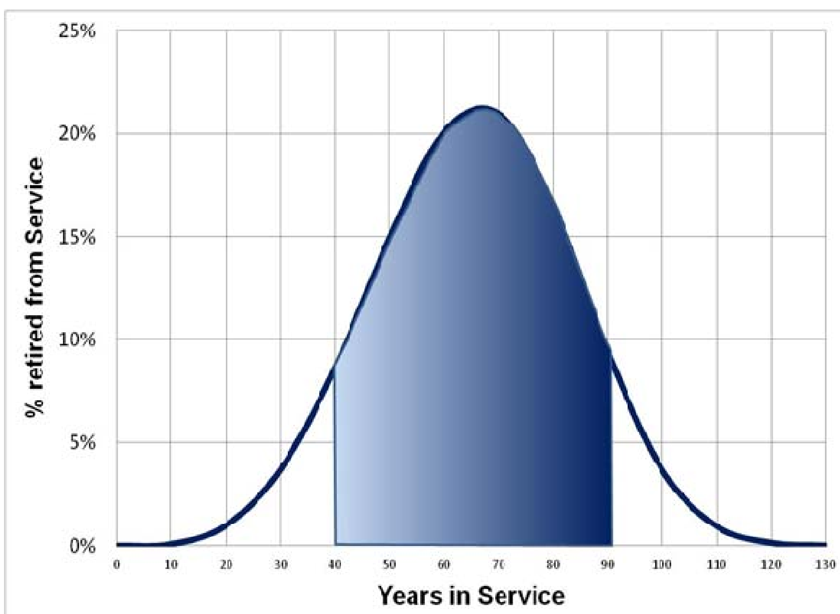
To understand the challenge posed by a wave of aging assets, it is necessary to understand the service life of each asset group. Examples of asset groups include pipelines, mains, services, meters, compression equipment, measuring and regulators. The concern is that a large population of the asset group would typically be retired from service near the average service life of the asset group, causing a spike in costs for asset replacement. The factors such as normal wear and tear, plus other external factors such as obsolescence, changes in codes and standards, economic efficiency, changes in service requirements, acts of nature, and third party damages, can all impact specific assets (Figure 6.2-2) and all need to be considered. These factors may result in early asset retirement in some cases, while an effective asset management program can also identify opportunities to optimize the service life of assets in the group.

Figure 6.2-2: Many Factors Impact the Service Life of an Individual Asset



Based on the estimates of the service life of our assets, over the next 40 years, approximately two-thirds of the current assets are expected to need replacement. As an example, Figure 6.2-3 illustrates the anticipated wave of asset replacement for FEU's pipe assets by showing their projected service life.

Figure 6.2-3: Projection of Gas Pipe Asset Renewal



CHANGING REGULATIONS AND EXPECTATIONS

The Oil and Gas Commission ("OGC") through regulation uses the CSA standard Z662 Oil and Gas Pipeline Systems to establish the minimum technical standards for the design, construction, operation, and maintenance of pipeline systems within B.C. In the 2007 Edition of the standard the concepts and specifications for asset Integrity Management and Safety and

Loss Management Systems were introduced. The Province also replaced the 40-year-old Pipeline Act with the Oil and Gas Activities Act, thus implementing a regulatory framework for managing risks to the environment and public safety due to all natural gas activities. The new Act addresses safety, transparency and consideration of "quality of life" impacts when working within prescribed distances of dwellings. As a result of these changes FEU has had to enhance its asset management systems and programs which will likely drive increased asset replacement.

Another example of increased regulation is the adoption by the OGC of CSA standard Z246.1 Security management for petroleum and natural gas industry systems that specifies requirements for security management planning and threat response. As a result FEU must continually review and update its security risk assessments and Security Management Program.

A number of high profile natural gas accidents have occurred across North America in recent years, heightening public concern for the safety of natural gas infrastructure. These heightened expectations are impacting asset management requirements, regulations and processes for utilities.

In November, 2000 an El Paso Natural Gas pipeline ruptured and caused a fire near Carlsbad, New Mexico. The incident led to the creation of the US Federal Pipeline Safety Improvement Act in 2002 to strengthen pipeline safety programs, oversight of pipeline operators, and public education on pipeline safety.

A more recent example is the September 2010 Pacific Gas and Electric gas pipeline failure and fire in San Bruno, California. A 30-inch diameter natural gas pipeline ruptured in a residential area. The accident killed eight people, injured many more, and caused substantial property damage. Approximately 47.6 million standard cubic feet of natural gas was released.[128] This accident has significantly increased public and regulator expectations on the safety of pipeline systems. For example, the incident has led to the introduction of a new Feinstein-Boxer safety bill to strengthen the Pipeline Safety and Enforcement Act of 2011, to mandate additional safety inspections and equipment installations, increase the number of safety inspectors, and increase the penalties for violation of regulations. These increases in prescriptive regulations in the US reflect public concerns regarding pipeline safety, and will very likely have implications for the entire industry in both the US and Canada.

Customers continue to expect reliable gas delivery and are increasingly less tolerant of an extended loss of service. The loss of gas supply can impact quality of life and comfort, and disrupt business. Regulatory authority investigations into long duration outages are expanding and requiring additional utility resources.

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[128] NTSB releases preliminary report on its investigation of pipeline rupture accident in California, http://www.ntsb.gov/pressrel/2010/101013.html

Given the need to manage and control the risks from aging assets, while balancing asset performance and cost effectiveness and meeting the challenges from increasing regulation and evolving stakeholder expectations, FEU must adopt a proactive approach and a long term view to manage its gas assets. This is the reason that FEU is applying and enhancing its asset management practices, particular in the planning of safety, reliability and integrity related sustainment capital, as explained below.

SUSTAINMENT CAPITAL AND ASSET MANAGEMENT

Given the challenge of the approaching wave of asset replacement and increasing regulation, an asset management approach and methodology is required which includes an analysis of the long term requirements of resources, as well as the ongoing asset management enhancement efforts. This will result in an optimized and levelized portfolio of capital investments matching available resources and minimizing rate impacts to our customers while continuing to ensure safe, secure natural gas delivery. As described below, FEU has made enhancements to its sustainment capital planning and asset management methodology that aim to reach this goal.

The methodologies to develop sustainment capital plans are linked to Asset Management. The Canadian Gas Association ("CGA") released a Guiding Document on Asset Management in 2009 that provides a basic framework for enhanced Asset Management practices. The CGA defines asset management as:

> *"A strategic management system used to optimally manage assets over the life cycle by balancing performance, risk, and expenditures to achieve corporate strategic objectives",*

and CGA further clarifies that asset management:

> *"…refers to a comprehensive and strategic application of a set of concepts, techniques, and tools that, when adopted and used effectively, can enhance a company's current management of its assets."*

The document goes on to describe the evolution of asset management practices:

> *"asset intensive industries such as aerospace, defence, oil and gas refineries, roads, bridges, railway works… have been developing this asset management discipline since the late 1970...* ***In more recent years, asset management has been gaining attention among North American transportation/municipal infrastructure managers and electric and gas utilities*** *(emphasis added)."*

In response to the need for a longer term and systematic sustainment capital planning and asset management strategy as described above, in 2010, FEU began developing a Long-Term Sustainment Plan (the "LTSP") for sustainment capital for transmission and distribution asset safety, integrity, reliability and capacity reinforcement. The LTSP is an enhancement to existing processes used for development of sustainment capital budgets. The primary enhancement is a life cycle view of asset health and management instead of the traditional one to five year view of assets. The LTSP is a longer term, more comprehensive and systematic process enhancement to the existing base capital planning on existing assets.

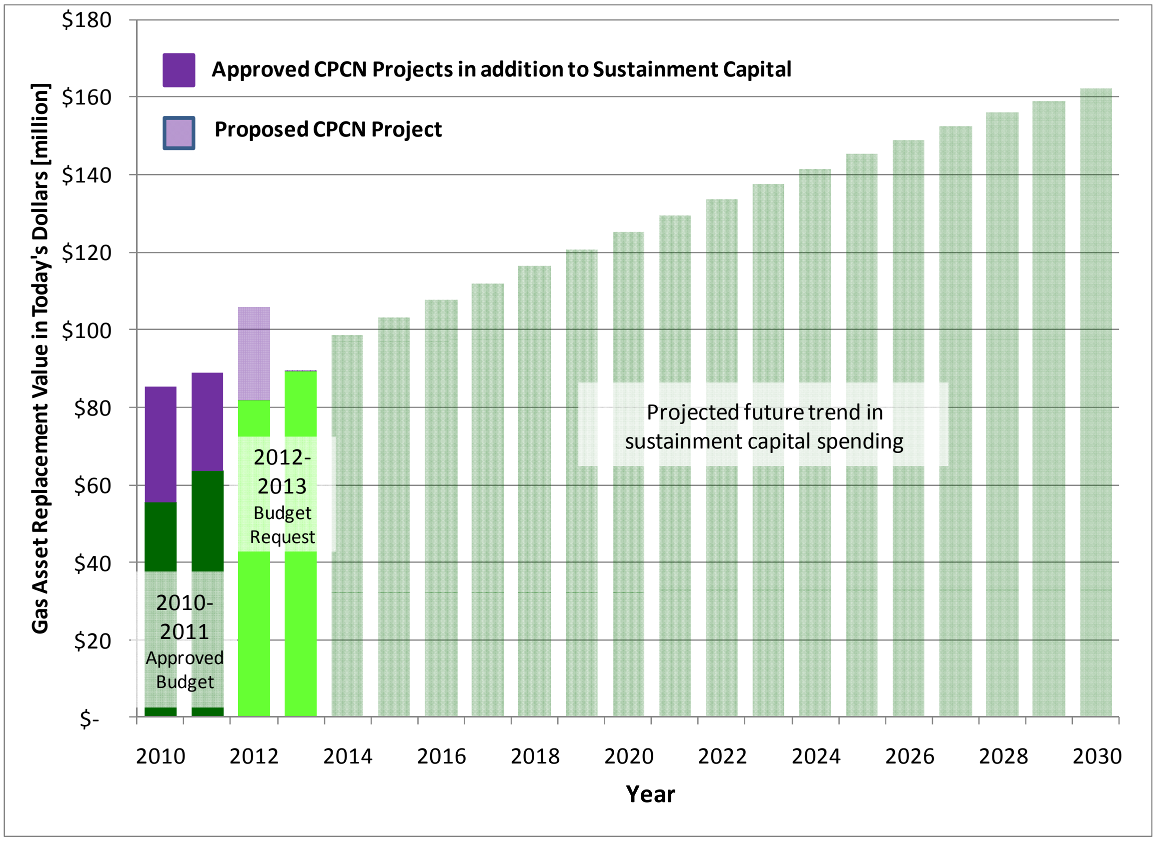
The enhanced sustainment planning process can be summarized into five elements.

- The Asset Registry links asset management modules, such as financial, geographic, maintenance and control systems, and establishes a clear and systematic hierarchy of assets and their inter-relationships so the overall system effectiveness can be measured;
- The Business Values defined for asset management purposes translate the corporate objectives of safe, reliable, environmentally responsible and cost effective energy service delivery into a set of metrics (quantitative and qualitative) that can be assessed against the impact of service failure;
- An Asset Health Review enables a more systematic view of risk, and includes a framework for asset failure prediction to ensure the correct data is collected and measurements are conducted to examine asset performance against expected service levels. A risk assessment is then conducted to quantify the impact on the Utilities' business values of both the consequence and probability of asset failure;
- The identification of defined levels of risk exposure triggers the preparation of a Business Case in which the problem is defined, feasible options are identified and evaluated, a preferred solution is selected, cost and resource requirements are determined and a project schedule is presented; and finally
- The various business cases for system sustainment projects are prioritized by the business value benefits to cost ratio.

The LTSP consists of two major groups of plans: System Reinforcement Plans and Integrated System Sustainment Plans. The sustainment capital falls within these two plans. This LTSP would coordinate with the accompanying O&M Plans to ensure appropriate operating strategies and maintenance efforts are applied to the assets. The cycle of conducting the asset management steps will be ongoing and continuously improving.

While it will take some time to fully implement the asset management enhancements, we have made important organizational, process and system advancements for the collection and assessment of data and to establish the technical and process foundations for improved trending of asset performance and service life prediction for all of FEU's assets. By knowing the age of our assets, using the service life curves (also known as Iowa Curves) generated based on the retirement history of our assets, and estimating the replacement costs of our assets in today's dollars, FEU is able to develop a projected trend of sustainment capital expenditure for all gas assets, as is shown in Figure 6.2-4. The wave of aging asset replacements is reflected by the rising trend of capital expenditure.

Figure 6.2-4: Projected Trend in Sustainment Capital



The 2012-2013 budgets have been more closely examined than long-term cost trending and are based on project specific estimates. As shown in the graph above, however, the 2012-2013 budget requests are consistent with our long-term view of the system from an asset health perspective.

For this Application, sustainment capital spending budgets have been developed using existing sustaining capital and some enhanced asset management practices. It should be noted that FEU is also addressing hazards and risks that the Company believes require immediate attention. Over the longer term, FEU will continue to improve its asset management practices with the further development of a Long Term Sustainment Planning process. Asset replacement costs are expected to continue to rise in the future because the cost of new assets will be higher than that of the original equipment. The LTSP will help us analyze a myriad of factors impacting asset replacement decisions and be used to prioritize spending where necessary and help to minimize the impact on rates by spreading costs out over time.

The approved, actual, projected, and forecast sustainment capital expenditures for transmission and distribution systems for all of the FortisBC Energy Utilities (FEU) are summarized in Table

6.2-5 below. The forecast for 2012 and 2013 is based on identifiable projects and represents a prudent and reasonable level of spending to provide reliable service.

Table 6.2-5: Approved, Actual and Forecast Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	19,700	20,307	20,580	20,755	21,925	22,566
Transmission System Reinforcements / Integrity and Reliabililty	14,591	13,607	16,531	16,531	28,448	30,714
Distribution System Reinforcements / Integrity and Reliabililty	10,159	6,559	11,276	11,726	10,195	8,705
Distribution Mains and Service Renewals and Alterations	11,212	12,542	10,957	12,853	21,757	27,605
	55,662	**53,015**	**59,344**	**61,865**	**82,324**	**89,590**

In this Application, FEU is seeking approval for 2012 and 2013 sustainment capital budgets for distribution and transmission assets. FEU has forecast $82.3 million in 2012 and $89.6 million in 2013 for Sustainment Capital expenditures. This represents incremental spending of $23.0 million and $30.2 million in 2012 and 2013 respectively over 2011 approved amounts for the same purposes. The project descriptions for the 2012 and 2013 projects are provided in the sections that follow. This two year sustainment spending includes:

- Expenditures for meter recalls and meter exchange programs;
- System reinforcements to the distribution and transmission systems to maintain capacity to meet existing customer demand and forecast load;
- Replacements and upgrades to the distribution and transmission systems to ensure safety, integrity and reliability; and
- Expenditures for main and service alterations and renewals.

The following sections describe the Sustainment Capital expenditures for each of the four utilities – Mainland, Vancouver Island, Whistler, and Fort Nelson.

6.2.2.2 Mainland Sustainment Capital Overview

The 2010 through 2013 Mainland Sustainment Capital is shown in the following table. Overall, Sustainment Capital in the Mainland utility is forecast to grow to $65.5 million in 2012 (increase of $21.7 million or almost 50 percent from 2011 Approved). The 2013 forecast is $75.1 million (an increase of $9.6 million or 15 percent from 2012 Forecast).

Table 6.2-6: Approved, Actual and Forecast Mainland Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	18,178	19,126	19,055	19,525	20,668	21,272
Transmission System Reinforcements / Integrity and Reliabililty	9,546	9,771	8,663	8,663	20,350	24,386
Distribution System Reinforcements / Integrity and Reliabililty	7,900	5,198	6,250	6,750	7,170	7,610
Distribution Mains and Service Renewals and Alterations	10,060	11,342	9,810	11,370	17,330	21,845
	45,684	**45,437**	**43,778**	**46,308**	**65,517**	**75,114**

Each of the four categories is discussed further below.

6.2.2.3 Meter Recalls and Exchanges – Mainland

This section contains a discussion of all meter capital, including both the recalls and exchanges included in Sustainment Capital, and the new meters included in Growth Capital. Similarly, the discussion of meter expenditures for Vancouver Island, Whistler and Fort Nelson below also includes both sustainment and growth meter expenditures.

The three main considerations in understanding the forecast meter expenditure level are:

1. the level of activity (meters purchased and installed or exchanged);
2. the unit cost to purchase, fabricate and install the meter (dollars per meter); and
3. other miscellaneous meter and regulator programs.

A summary of 2011 Meters (New and Replacement) projections as well as 2012-2013 forecast activities, unit costs, and expenditures follows in Table 6.2-7 below. The level of activities combined with the unit cost form the basis for the total expenditures.

Table 6.2-7: Approved, Actual and Forecast Mainland Meters Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities						
Meters - Exchange	60,255	61,540	60,175	61,853	62,350	62,300
Meters - New	5,952	6,949	6,166	6,361	6,656	6,923
Unit Costs ($/meter)						
Meters	$ 267	$ 274	$ 280	$ 280	$ 295	$ 304
Expenditures ($000's)						
Meters - Exchange	$ 16,079	$ 16,873	$ 16,861	$ 17,331	$ 18,408	$ 18,945
Meters - Other	$ 2,099	$ 2,253	$ 2,194	$ 2,194	$ 2,260	$ 2,328
Total Sustainment	$ 18,178	$ 19,126	$ 19,055	$ 19,525	$ 20,668	$ 21,272
Meters - New	$1,588	$ 1,905	$1,728	$ 1,782	$ 1,965	$ 2,105

METERS ACTIVITY LEVELS

The forecast level of meter activity is derived from the sum of the customer additions and the meter exchange forecasts. The meter forecast for new customers is derived directly from the forecast of customer additions using a one to one ratio. The forecast level of meter exchange activity to service existing customers is driven by life expectancy of meters and the total size of the meter population.

In the past few years, there were two specific drivers that significantly influenced the meter recall schedule. Prior to 2006, we managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, provided us with the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. This allowed the Mainland to temporarily reduce the number of meter recalls from between 40,000 to 50,000 meter recalls annually to a range between 25,000 to 35,000 recalls annually over the period 2006 - 2008. The reduction in the number of recalls brought the demographics of the meter fleet in line with a 20 year life expectancy, which provide customers with the cost benefits of previous investments in the fleet.

Forecast meter exchanges for 2012 and 2013 of approximately 62,000 per year are consistent with recent activity levels observed. Of the 62,000 forecast per year, approximately 58,000 are for the residential meter recalls program as well as unscheduled residential meter exchanges. The remaining units (approximately 4,300) are identified for the industrial meter exchange program (seven year exchange frequency) as well as unscheduled industrial meter exchanges.

We believe the established meter recall frequencies reflect the long term objectives of the fleet management program and will ensure our customers will continue to receive service that is both cost effective and reliable.

METERS UNIT COSTS

Aggregate or blended meter unit cost, which is the second consideration in establishing the forecast expenditure requirement for meters, is influenced by the type, size, and design of the meter, installation, fabrication and exchange conditions and the timing of bulk meter purchases and meter/regulator upgrade activity. A blended unit cost of all customer types is used for meter exchanges and installs. Meter unit costs typically range from $75 to $10,000 depending on customer requirements. In 2010, the blended meter unit cost consists of 35 percent labour and 65 percent material costs. Unit costs for meters for 2012 and 2013 are based on 2010 actuals and 2011 forecast inflation on labour and materials of 3 percent per annum. Also included in the 2012 unit cost increase is an incremental $6 per meter to reflect additional funding required for customer meter set upgrades and alterations. These upgrades are primarily on industrial/commercial meters to address obsolescent components and to facilitate field maintenance (i.e. the installation of a by-pass mechanism to eliminate a customer shutdown during routine meter maintenance).

METERS EXPENDITURES

In Table 6.2-7 above, the Exchange Meters expenditures forecast for 2012 and 2013 is $18.4 and $18.9 million respectively. Meters expenditures are variable and rise and fall with meter exchange activity levels. The regulators required for replacement activities are included in the “Meters-Other” category. In 2012 and 2013, $2.3 million is required for a continuation of the annual regulator ever-greening requirement. This is a program started in 2003 in Mainland to replace regulators at the same time as meters were replaced at the customer premise. The forecast in meter exchange activity levels together with the regulator replacement program is reflected in the aggregate expenditure requested.

6.2.2.4 Transmission System Reinforcement, Integrity & Reliability Capital – Mainland

These Transmission-related capital expenditures include system capacity improvements to meet existing customer demand and forecast load, and expenditures related to ensuring safety, reliability and integrity of the transmission system, as well as to minimize impact to the environment.

As shown in Table 6.2-6 above, the 2010 approved expenditure for the Mainland was approximately $9.6 million while the actual expenditure was approximately $9.8 million, a difference of 2 percent. It is expected that 2011 expenditures will be very close to the approved amount of approximately $8.7 million. The forecasts for Mainland Transmission expenditures in

2012 and 2013 are $20.4 and $24.4 million, respectively. The primary reason for the higher forecasts is the implementation of the LTSP.

2012 and 2013 projects that are forecast to cost greater than $1 million and significant multi-year programs are discussed below:

COMPRESSOR STATION CONTROL UPGRADE PROGRAM

In 2007, the manufacturer of the electronic control equipment commonly used in all 9 compressor stations served a 24 month notice of inactivation – i.e. the equipment will no longer be manufactured and there will be no guarantee of inventory or spare parts. To address this equipment obsolescence, a replacement program, which began in 2009, will require $1.3 million between 2012 and 2013 to update the electronic control technology. The program will continue until its completion in 2016.

INTERIOR TRANSMISSION SYSTEM VALVE REPLACEMENT PROGRAM

Over 40 percent of 1,515 km of pipeline in the Interior Transmission System are 40 years and older. There are over 90 valve assemblies on the older portion of the pipeline system that are exhibiting deterioration in operational performance such as high operating torque, and stem and seal leaks that are difficult to repair due to the below ground installations. A program was initiated in 2008 to systematically replace the aging valve assemblies with above ground designs on a priority basis based on operational criticality, proximity to people and potential third party activity, and accessibility for emergency response, etc. The program will continue to 2016 with planned expenditures of $2.4 million and $2.2 million in 2012 and 2013, respectively.

MAJOR INSPECTION OF PIPELINES

Major expenditures for on-going inline inspection of the major transmission pipelines will cost $1.5 million and $1.3 million, respectively in 2012 and 2013. These spending levels are similar to that experienced in 2010 and 2011.

PHYSICAL SECURITY IMPROVEMENT

With the anticipated adoption by the Oil and Gas Commission of CSA Z246.1-09, *Security management for petroleum and natural gas industry systems*, security upgrades are planned for the critical and vulnerable assets on the transmission systems. These upgrades will occur on an on-going basis in response to regular security criticality, threat and vulnerability assessments. For 2012 and 2013, physical security improvement such as access control, vehicular barricade, active video monitoring and alarms, and improved fencing, etc. in the amount of $1.6 million and $1.2 million, in 2012 and 2013 respectively, will be added to several critical transmission facilities.

COASTAL TRANSMISSION SYSTEM VALVE REMOTE AUTOMATION PROGRAM

The Coastal Transmission System, located in an urban and seismically-sensitive area, has a relatively high probability of damage from third-party activities and natural ground movement. The consequence of a pipeline rupture, in the form of property damage or personal injury or fatality, is also correspondingly greater in the Lower Mainland due to the higher population density. The ability to remotely close valves will allow operations personnel to address such emergency situations quickly and safely. The ability to close valves in a more timely manner will mitigate the potential consequences of a transmission pipeline rupture by the reducing the amount of vented gas, reducing the possibility of fire damage, and reducing physical exposure to danger for operations personnel, emergency responders and the public. This program will automate 49 mainline and crossover valves in 17 valve assembly sites, spanning 4 years from 2012 to 2015, with an expenditure of $2 million per year in each of 2012 and 2013.

PIPELINE IN-LINE INSPECTION IMPROVEMENT

The major transmission pipelines are subject to in-line inspection (“ILI”) for monitoring of corrosion and other conditions affecting pipeline integrity. The inspection provides a proactive approach to preventing pipeline failure. However, there are several small pipe segments where the ILI launchers/receivers for the inspection tools are not yet installed, thus not allowing ILI for these pipe segments.

Since installation in 1989, the 610 mm OD pipeline from Noons Creek to Eagle Mountain, interconnecting the Coastal Transmission System to the Vancouver Island Transmission System, could not be shut down for ILI launcher/receiver installation as it is the single feed to Vancouver Island. However, with the completion by the end of 2011 of the Mt. Hayes LNG Facility near Ladysmith to provide an alternate source of gas supply to Vancouver Island this single feed line can finally be temporarily isolated. The ILI launcher/receiver installation for the Noons Creek to Eagle Mountain Pipeline is planned to take place in 2012 at a budgetary cost estimate of $1.5 million.

SEISMIC UPGRADES

The transmission and distribution systems in the Lower Mainland operate in a zone of high potential seismic activity. An updated Regional Seismic Risk Assessment (last performed in 1994) was completed in late 2010 with seven high priority pipeline segment sites identified. Site specific geotechnical assessments are underway for these sites to be followed by assessments of the actual pipelines at each site and, where necessary, further work to finalized the scope and cost of both geotechnical and pipeline remediation to mitigate the threats posed by potential seismic events.

Based on preliminary geotechnical and pipeline assessments, the pipelines connecting the Tilbury Transmission Valve Assembly to the Tilbury LNG Facility have been identified as requiring remediation in the period 2012 to 2013. The two pipelines cross an area with significant potential for seismically induced soil liquefaction and lateral ground spreading, putting both lines at risk of failure. A preliminary estimate for geotechnical remediation in the form of Ground Improvement ("GI") barriers is $1.0 million and the remediation work is currently scheduled to be completed in 2012

DEPTH OF COVER RESTORATION ON AGING PIPELINES

Sufficient depth of cover of a pipeline is an important mitigation strategy for reducing the risk of third party damage and providing safe, efficient and reliable operations. A contractor has been retained to perform depth of cover surveys along portions of the Interior Transmission System. So far, these surveys have recorded a number of low depth of cover locations as well as a few instances of pipeline exposure. These sites are predominantly on older pipelines. Such locations in combination with areas of cultivation activity raise the risk of third party damage to the pipeline that could lead to failure and prevent safe and reliable gas delivery.

Remedial action is proposed to lower the risk of third party pipeline damage. The most effective means of risk reduction while maintaining cost, schedule and resource efficiency is to perform a series of restoration projects at the highest risk segments within a 5 year plan. The initial 5 year plan calls for restoring the depth of cover over approximately 7.5 kms of pipeline at high risk locations of the Interior Transmission System. Further surveys and analysis will be perfomed during these 5 years to determine the risk levels of other areas of significant loss of cover to develop future mitigation plans.

To ensure resource allocation and avoid scheduling difficulties, the 5 year plan will be divided into yearly projects commencing in 2012. During 2012 we will restore depth of cover over approximately 0.5kms of pipeline at a cost of $1.0 million and during 2013, over approximately 2.5kms of pipeline at a cost of $5.0 million.

6.2.2.5 Distribution System Reinforcement, Integrity & Reliability Capital – Mainland

These Distribution expenditures primarily focus on improvements to flow and pressure regulating stations and installation of pipe to increase the capacity of the distribution systems. Also included are upgrades to the transmission pressure laterals which are not part of the Interior Transmission System, and the associated cathodic protection installations.

As shown in Table 6.2-6 above, the 2010 approved expenditures for the Mainland was $7.9 million. The actual expenditure was approximately $5.2 million. The decrease was primarily due to:

- A relocation of the Highland Valley Lateral was approximately half the estimate submitted for budgeting due to the requestor providing their own resources at their own cost. This reduced expenditures by approximately $1 million.

- A relocation of the PG#2 Lateral was delayed until 2011 in conjunction with municipal road construction which deferred expenditure of approximately $200 thousand.
- Deferral of system improvement installations in accordance with recent reduced customer growth forecasts resulted in a deferral of $600 thousand to later years.
- Completion of an upgrade to the Coquitlam Gate Station was deferred until 2011 so a more thorough assessment could be completed in order to clearly understand the necessary scope of work. Materials were obtained later in the year; however the field work was not undertaken resulting in a deferral of approximately $350 thousand to 2011.

During 2012 and 2013 there are no programs or projects being undertaken that are greater than $1 million.

6.2.2.6 Distribution Mains, Service Renewals and Alterations Capital – Mainland

These expenditures primarily consist of replacement of intermediate pressure and distribution pressure mains and services either to address integrity concerns identified by the Company or to address location concerns raised by others. On occasion this category also includes upgrades to the Revelstoke Propane Plant and the installation of new pressure regulating stations.

As shown in Table 6.2-6, 2010 Actual and 2011, projected expenditures are higher than Approved. Drivers for this include an increase in federal, provincial and municipal infrastructure improvement projects that necessitate alterations to existing mains and services, and the Company taking advantage of opportunities to replace mains and services that have integrity concerns when others have already disturbed the ground surface. This avoids pavement replacement costs and costs associated with unplanned work to respond to pipe leaks. This trend is expected to increase over time as municipalities implement programs to upgrade their infrastructure and we undertake similar actions at the same time.

The forecast expenditure in this category for 2012 and 2013 is $17.3 million and $21.8 million respectively. The amount expended over recent years has not varied significantly; however, the initiation of the LTSP has resulted in the identification of a variety of integrity concerns with respect to steel mains and services and a resulting increase in the forecasts for 2012 and 2013. The Company has been able to determine the extent of these concerns in many cases and as a result, proposes the implementation of the following programs to address these concerns in a timely manner. Projects discussed below are anticipated to exceed $1 million in the forecast 2012-2013 periods.

UNPROTECTED DP MAINS AND SERVICES – LOWER MAINLAND

This program consists of replacing 18,340 metres of unprotected steel distribution pressure main and the approximately 2,000 associated services in the Lower Mainland over an 8 year period.

Approximately 103 sections of main have been identified in the Lower Mainland that cannot be protected by cathodic protection due to very poor coating and insufficient cathodic protection current. CSA Standard Z662, Oil and gas pipeline systems, requires that steel pipe be protected from corrosion. Replacing the steel pipe, in most cases being very old, with new polyethylene pipe will prevent leaks and the higher costs associated with unplanned repairs.

The program will have significant impact on municipal infrastructure, such as roads, and extensive coordination with municipal projects is planned.

The proposed expenditure is $1.2 million and $4.5 million in 2012 and 2013 respectively.

LOUGHEED HWY MAIN REPLACEMENT PROJECT

The Lougheed Highway Main Replacement project consists of replacing approximately 4.5km of existing 168mm steel main with polyethylene pipe along the existing route or along another, as the existing steel main has had periods of significant leaks and unusual failures.

As it is very likely there will be future leaks or pipe failures, the installation of new pipe will reduce the probability of a significant interruption to the operation of Skytrain[129] and interference with the primary highway thoroughfare. Other sections have been replaced in the past.

It will be necessary to undertake design and community relations activities in 2012 with construction to occur in the following 2 years.

The proposed expenditure is $375 thousand and $1.5 million in 2012 and 2013 respectively with project completion in 2014.

DP MAINS MAINLAND RENEWAL PROGRAM

This program involves the replacement of aging steel mains and services with polyethylene mains and services based on internal priority and in conjunction with municipal infrastructure upgrade projects.

Buried pipe assets are aging and many are approaching the established useful life of approximately 65 years. Within Mainland and Vancouver Island, 113km (17 percent) of Intermediate Pressure and 3,500km (16 percent) of Distribution Pressure buried pipe are over

[129] A recent leak caused the shutdown of the Skytrain.

50 years old. As the pipe ages, is it likely that it will need to be replaced due to integrity concerns, lack of capacity or third party activity such as municipal infrastructure upgrades. Replacing the steel pipe with polyethylene pipe or with steel having better coating results in a safer, more reliable system with less concern regarding maintaining integrity or having to undertake emergency repairs.

This type of work is currently undertaken to a limited extent. We are forecasting an increase of $2.5 million starting in 2012 to address additional projects in coordination with third parties, such as municipalities. Various municipalities have announced that they intend to ramp up their spending to upgrade their infrastructure and thus excavate roads and work around our pipe.

The proposed expenditure is $2.5 million in each of 2012 and 2013 respectively.

6.2.2.7 Vancouver Island Sustainment Capital Overview

The 2010 through 2013 Vancouver Island Sustainment Capital is shown in the following table. Overall, Sustainment Capital in the Vancouver Island utility is forecast to grow to $16.3 million in 2012 (increase of $3.6 million or almost 30 percent from 2011 Approved). The 2013 forecast is $14.2 million (a decrease of $2.1 million or 13 percent from 2012 Forecast).

Table 6.2-8: Approved, Actual and Forecast Vancouver Island Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustaining Capital						
Meter Recalls/Exchanges	1,492	1,134	1,496	1,188	1,215	1,250
Transmission System Reinforcements/Integrity & Reliabililty	5,045	3,836	7,868	7,868	8,098	6,328
Distribution System Reinforcements/Integrity & Reliabililty	1,520	991	2,315	2,315	2,685	935
Distribution Mains, Service Renewals and Alterations	1,000	1,156	1,000	1,326	4,276	5,646
	9,057	**7,117**	**12,679**	**12,697**	**16,274**	**14,159**

Each of the four categories is discussed further below.

6.2.2.8 Meter Recalls and Exchanges – Vancouver Island

This section contains a discussion of all meter capital, including both the recalls and exchanges included in Sustainment Capital, and the new meters included in Growth Capital.

The three main considerations in understanding the forecast meter expenditure level are:

1. the level of activity (meters purchased and installed or exchanged);
2. the unit cost to purchase, fabricate and install the meter (dollars per meter); and
3. other miscellaneous meter and regulator programs.

A summary of 2011 Meters (New and Replacement) projections as well as 2012-2013 forecast activities, unit costs, and expenditures follows in Table 6.2-9 below. The level of activities combined with the unit cost form the basis for the total expenditures.

Table 6.2-9: Approved, Actual and Forecast Vancouver Island Meters Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities						
Meters - Exchange	6,410	6,155	6,250	6,250	6,210	6,210
Meters - New	2,320	2,432	2,430	2,415	2,557	2,656
Unit Costs ($/meter)						
Meters	$ 233	$ 177	$ 239	$ 182	$ 188	$ 193
Expenditures ($000's)						
Meters - Exchange	$ 1,492	$ 1,134	$ 1,496	$ 1,188	$ 1,215	$ 1,250
Meters - New	$ 540	$ 430	$ 582	$ 440	$ 480	$ 513

METERS ACTIVITY LEVELS

As with the Mainland, the forecast level of meter activity for Vancouver Island is derived from the sum of the customer additions and the meter exchange forecasts. The meter forecast for new customers is derived directly from the forecast of customer additions using a one to one ratio. The forecast level of meter exchange activity to service existing customers is driven by life expectancy of meters and the total size of the meter population.

The meter exchange program on Vancouver Island is managed centrally through the Mainland Measurement department. Prior to being centralized, the meter exchange program was a "just in time" program where meter exchange levels were established based on original install dates and estimated life expectancy. Consistent with the program established for the Mainland, Vancouver Island will be exchanging the meter fleet in line with 20 year life expectancy on residential meters. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the Company's own internal analysis, has provided confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. The 20 year life span is the financially optimal target, balancing the risk (cost) of unscheduled failure with the replacement cost. An unscheduled failure is generally disruptive to the customer and more costly to execute in the field as compared to a scheduled replacement which can be completed at both the customer's and Company's convenience.

The early 1990s was a period of high customer (meter) growth for Vancouver Island and meters installed during this period are coming due for exchange. It is no longer viable to maintain lower exchange levels as the result of an aging meter fleet and anticipated early failures for some batches of meters purchased. In the 1990s, certain batches of meters were comprised of components constructed with less durable materials and, although the vendor has since re-designed the meter to address this concern, it is prudent to proactively remove these meters from the fleet to prevent unscheduled failures. This meter recall frequency reflects the long term objectives of the fleet management program and will ensure customers will continue to receive service that is both cost effective and reliable.

METERS UNIT COSTS

Meter unit cost, which is the second consideration in establishing the forecast expenditure requirement for meters, is influenced by the type, size, and design of the meter, installation, fabrication and exchange conditions and the timing of bulk meter purchases. A blended unit cost of all customer types is used for meter exchanges and installs. Meter unit purchase costs can range from $75 to $10,000 each depending on the customer requirements. Including installation costs, the meter unit cost consists of approximately 35 percent labour and 65 percent material costs.

Unit costs for meters for 2012 and 2013 are based on 2011 projections adjusted for, labour and material inflation at 3 percent.

METERS EXPENDITURES

In Table 6.2-9 above, the Exchange Meters expenditures forecast for 2012 and 2013 is $1.2 and $1.3 million respectively. Meters expenditures are variable and rise and fall with meter exchange activity levels.

6.2.2.9 Transmission System Reinforcement, Integrity & Reliability Capital – Vancouver Island

These transmission-related capital expenditures include system capacity improvements to meet existing customer demand and forecast load, and expenditures related to ensuring safety and reliability of the transmission system, as well as to minimize the impact to the environment.

As shown in Table 6.2-8 above, the 2010 approved expenditures for Vancouver Island Transmission was $5.1 million. The actual expenditure was approximately $3.8 million. The decrease was primarily due to planned projects not materializing in the year.

The forecasts for transmission expenditures in 2012 and 2013 are $8.1 and $6.3 million, respectively as shown in Table 6.2-8 above.

6.2.2.10 Distribution System Reinforcement, Integrity & Reliability Capital – Vancouver Island

As shown in Table 6.2-8 above, the 2010 approved expenditure for Vancouver Island was $1.5 million. The actual expenditure was approximately $1.0 million. The lower amount incurred was primarily due to the deferral of distribution pressure system improvements due to revised lower growth forecasts ($250 thousand), delayed system improvement projects due to the routes not being ready ($452 thousand) and approved projects that were not completed by year end ($200 thousand).

The forecasts for distribution expenditures in 2012 and 2013 are $2.7 and $0.9 million, respectively as shown in Table 6.2-8 above. The primary difference between the years is due to the expenditures for system improvements to address customer growth, which are projected to be $2.1 million in 2012 and $0.3 million in 2013. Station upgrades including telemetry, required by customer growth and changes to facility requirements, generally, make up the balance of the expenditures in 2012 and 2013.

In 2012 and 2013, only one project is forecast to cost greater than $1 million, and is discussed below.

To address growth on the Saanich peninsula a 1.5km long loop of the existing intermediate pressure system is necessary. As an example of the customer growth, the expanded regional hospital lies within the area to be served by the proposed project. The preliminary design recommends that the pipe be 323mm OD and the preliminary cost estimate is $1.5 million, the majority of which is to be incurred in 2012. Design is to be undertaken in 2011.

6.2.2.11 Distribution Mains, Service Renewals and Alterations Capital – Vancouver Island

These expenditures on Vancouver Island primarily consist of replacement of intermediate pressure and distribution pressure mains and services either to address integrity concerns identified by the Company or to address concerns about the location of our pipes raised by others, such as municipalities and developers. On occasion this category also includes the installation of new pressure regulating stations. A summary of the proposed expenditures is contained in Table 6.2-8 above.

The amount expended over recent years has not varied significantly; however the initiation of the LTSP has resulted in the identification of a variety of integrity concerns with respect to steel mains and services that will result in increased expenditures in 2012 and 2013. The Company has been able to determine the extent of the concern in many cases and as a result we are implementing the following programs to address the concerns in a timely manner.

The projects discussed below are anticipated to exceed over $1 million in the forecast 2012-2013 periods.

REPLACE ISOLATED STEEL MAINS AND SERVICES – CAPITAL REGIONAL DISTRICT

Of a total of 50 segments of isolated steel main, Corrosion Control has identified 28 as being high priority for replacement due to difficulties associated with maintaining adequate cathodic protection current levels to prevent corrosion. 17 of the 28 segments are less than 200m long.

Replacing the existing steel main and the associated services with polyethylene pipe will eliminate the need for special monitoring of the 50 sections of main and thus reduce O&M costs from current levels. Replacement will also avoid increased O&M costs over time as the pipe ages and anodes must be replaced on an increasing frequency. Some agencies have expressed concerns regarding the environmental impact of sacrificial magnesium anodes. Replacement with polyethylene pipe will avoid dealing with any resistance there may be to granting permission to install replacement or additional anodes.

The higher priority sites are to be address over the 2012 – 2013 periods with the forecast expenditure being $1.3 million and $2.7 million in 2012 and 2013 respectively. The project will be continuing in the future as the remaining sites are re-evaluated and prioritized.

DP MAINS ISLAND RENEWAL PROGRAM

This program, identical to the DP Mains Mainland Renewal Program discussed above, consists of the replacement of steel mains and services with polyethylene mains and services based on internal priority and in conjunction with municipal infrastructure upgrade projects.

An increase in expenditure is expected to be needed as municipalities ramp up their spending to upgrade their infrastructure and thus excavate roads and work around our pipe.

The forecast expenditure is $1.5 million in each of 2012 and 2013 respectively.

6.2.2.12 Whistler Sustainment Capital Overview

The 2010 through 2013 Whistler Sustainment Capital is shown in the following table. Overall, Sustainment Capital in Whistler is forecast to grow to remain relatively stable over the forecast period.

Table 6.2-10: Approved, Actual and Forecast Whistler Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	27	44	27	41	41	42
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	10	45	-	-	-	-
Distribution Mains and Service Renewals and Alterations	82	27	84	94	88	81
	120	**116**	**111**	**134**	**129**	**123**

6.2.2.13 Meter Recalls and Exchanges - Whistler

Meter activity levels are based on meters required to service new customers as well as meters exchanged for existing customers. The meters related to new customers are driven by the number of customer additions and the meters required for exchange activities are driven by Measurement Canada standards and the in-house program established to meet these standards. Meter unit cost is a blended amount of residential, commercial and industrial meters and forecast amounts for 2012 and 2013 reflect the most recent actual experience of 2010 with natural gas meters. Forecast meter expenditures for 2012-2013 are similar to 2010 actuals. The majority of these meter costs are related to the number of meter exchanges which are unchanged from previous years.

6.2.2.14 Distribution System Reinforcement, Integrity & Reliability Capital – Whistler

Whistler has limited facilities that fall within the scope of this category and thus on occasion there will not be a need for capital expenditure. This is the case for the 2011 through 2013 period.

The 2010 approved expenditure in Whistler was $10 thousand while the actual expenditure was $45 thousand. The expenditure was to address the replacement of valves at the Whistler District Station as they were found to leak gas when they were closed

6.2.2.15 Distribution Mains, Service Renewals and Alterations Capital – Whistler

In 2010 the actual expenditure was $55 thousand less than expected due to an anticipated main relocation within the village not materializing. There is no unusual activity anticipated within the Whistler system during 2012 or 2013. The forecast expenditures are required to address concerns regarding relocations of mains and services and hazards as they are found.

6.2.2.16 Fort Nelson Sustainment Capital Overview

The 2010 through 2013 Fort Nelson Sustainment Capital is shown in the following table. Overall, Sustainment Capital in Fort Nelson is forecast to return to normal levels after the completion of the Muskwa River crossing project in 2011.

Table 6.2-11: Approved, Actual and Forecast Fort Nelson Sustainment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	3	3	2	2	2	2
Transmission System Reinforcements / Integrity and Reliabililty	-	-	-	-	-	-
Distribution System Reinforcements / Integrity and Reliabililty	729	325	2,711	2,661	340	160
Distribution Mains and Service Renewals and Alterations	69	17	63	63	63	33
	801	**345**	**2,776**	**2,726**	**405**	**195**

6.2.2.17 Meter Recalls and Exchanges – Fort Nelson

Forecast meter expenditures are required for new and replacement activities. There is minimal activity expected in 2011, and 2012 and 2013 forecasts are based on 2011 projections.

6.2.2.18 Distribution System Reinforcement, Integrity & Reliability Capital – Fort Nelson

Natural Gas service to the Fort Nelson area is provided by a single 114mm transmission pressure pipeline that crosses the Muskwa River on the southeast side of the town. This pipeline has become exposed and is now at risk of damage from river action. Expenditures are required to replace the pipeline crossing. As approved by the Commission in Order No. G-27-11, a river crossing replacement utilizing the adjacent highway bridge is projected to be the most cost-effective strategy. Total project costs for this option are currently estimated at $3.0 million (excluding AFUDC), unchanged from the approved amount. Of this total, approximately $2.9 million will be added to rate base in late 2011, with the remainder being added in 2012.

Capital expenditures in 2012 and 2013 are much lower than that of 2011 due to a return to more a typical capital expenditure period once the Muskwa River concern is addressed. However they are higher than the years prior to 2010 and 2011. The increase is primarily due to expenditures required for the replacement of existing equipment due to obsolescence and to address anticipated customer growth.

6.2.2.19 Distribution Mains, Service Renewals and Alterations Capital – Fort Nelson

These expenditures primarily consist of replacement of intermediate or distribution pressure mains and services either to address integrity and reliability concerns identified by the Company or to address location concerns raised by others.

In 2010 the actual expenditures were $17 thousand compared to a budget of $69 thousand. The lower expenditure was due to a decision by the City of Fort Nelson to convert its pump station heating system to electricity rather than continue to use natural gas. This cancelled a planned $20 thousand upgrade to the local station. As well, we were not able to implement a $30 thousand program to remove culverts and valves that are no longer needed and pose a public safety risk due to structural deterioration. We anticipate that we will be able to address these in 2011. There is no unusual planned activity anticipated within the Fort Nelson system during 2012 or 2013. The funds required are to address concerns regarding relocations of mains and services and hazards as they are required.

6.2.2.20 System Sustainment Capital Summary

The proposed level of Sustainment Capital expenditure is considered prudent and reasonable, particularly when considered in terms of the nature and age of the transmission and distribution systems. Much of the infrastructure is over 40 years old and requires a significantly higher level of capital expenditure to ensure that FortisBC Energy Utilities meets its commitments to public safety, code requirements, environmental performance and its obligation to provide dependable, reliable service.

6.2.3 GROWTH CAPITAL EXPENDITURES

Growth Capital expenditures include the installation of new mains, services, meters and regulators. Also, new to Growth Capital in 2011 are expenditures for biomethane and NGV projects. The primary drivers for Growth Capital expenditures are the number and type of new services and mains. These in turn are driven by customer additions, which are dependent on new housing, development activity and market capture. The descriptions that follow for new mains, services, meters and regulators are applicable across all four utilities.

Main expenditures consist of new main extensions with a number of different attributes including location, size of pipe, and length of extension, pressure and type of material. Proposed main extension projects are evaluated through a main extension economic test ("MX Test") which analyzes cost estimates for installing the main, projections in numbers of customers attached as well as forecast customer gas usage. Uneconomic results require contributions from customers in order for the planned extensions to proceed.

Service expenditures consist of a variety of service types for new customers. These include new and conversion, distribution and intermediate pressure services to single and multi-family dwellings, gas stub service from the main, services installed from the stub, vertical header subdivisions (a vertical service line system within a building such as a high-rise) and distribution and intermediate new or conversion service header mains, and distribution and intermediate service header laterals. Service header mains are distribution mains installed on private property (i.e. multi-family strata owned complexes). Stubs are service extensions off of the main installed with the main in new subdivisions to eliminate road cuts and pavement repairs at a future date. There are two basic considerations in understanding the forecast service expenditures level. These are level of activity (number of services installed, number of service header mains installed) and aggregate unit cost to install the service (dollars per service) and/or service header main (dollars per meter).

Meter and regulator expenditures consist of new meters and regulators to serve new customers. The two main considerations in understanding the forecast meter expenditure level are: (1) the level of activity (meters purchased and installed); and (2) the unit cost to purchase, fabricate and install the meter (dollars per meter). Growth meter expenditures have been discussed above in the sustainment capital section.

Biomethane and NGV expenditures are a new category of products offered by FEU and discussed in more detail in Appendix J and Appendix I respectively.

Below in Table 6.2-12 is a summary of the approved, actual, projected, and forecast Growth Capital expenditures for the combined FortisBC Energy Utilities.

Table 6.2-12: Approved, Actual and Forecast Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	11,595	6,616	12,318	8,521	9,116	9,657
New Customer Services	20,781	19,337	22,480	15,787	17,069	18,279
New Customer Meters	2,147	2,348	2,323	2,232	2,455	2,629
Biomethane/NGV	-	-	-	7,004	7,078	7,378
	34,523	**28,301**	**37,122**	**33,544**	**35,717**	**37,943**

The following sections describe the Growth Capital expenditures for each of the four utilities – Mainland, Vancouver Island, Whistler, and Fort Nelson.

6.2.3.1 Mainland Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for the Mainland are summarized in Table 6.2-13 below.

Table 6.2-13: Approved, Actual and Forecast Mainland Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	8,807	4,538	9,306	5,738	6,124	6,497
New Customer Services	14,722	13,874	15,940	11,175	12,044	12,903
New Customer Meters	1,588	1,905	1,728	1,782	1,965	2,105
Biomethane/NGV				7,004	7,078	7,378
	25,117	**20,317**	**26,974**	**25,699**	**27,211**	**28,883**

6.2.3.2 Mains - Mainland

The drivers of the mains capital additions - forecast mains activity and unit costs - are summarized in Table 6.2-14 below.

Table 6.2-14: Approved, Actual and Forecast Mainland Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	112,136	81,259	116,166	100,724	105,395	109,623
Unit Costs ($/meter)	$ 79	$ 56	$ 80	$ 57	$ 58	$ 59
Expenditures ($000's)	$ 8,807	$ 4,538	$ 9,306	$ 5,738	$ 6,124	$ 6,497

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are each described in the following sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year (2008-2010) historical ratio of 0.72 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 13.7 metres of new Main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

The actual mains activity levels in 2010 were considerably lower than the approved levels largely due to the downturn in the economy in late 2008, a buildup of new mains infrastructure in 2005-2008, the beginning of a period of lower new subdivision activity in 2009 and decreases in housing starts in 2009. Typically, a new main takes up to five years to be fully utilized with service attachments prior to additional main extensions being required. Mains activity levels peaked in 2008 at 200,167 metres which equated to 19 metres of new main per service installed. The comparative ratio in 2010 was approximately 9 metres of new main per service installed reflecting the absence of developers seeking main extensions for new housing developments.

Projected new mains activity levels for 2011 are 100,724 metres based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new mains activity has been forecast at 105,395 and 109,623 metres, respectively.

MAINS UNIT COSTS

The forecast unit costs for 2012 and 2013 reflect the unit cost experience of 2010 inflated by 2 percent annually. The mains work has seen a slight shift back to install contractors. We maintain workforce levels sufficient to respond to emergencies. Consequently, our company workforce mains unit costs are historically higher than contractors due to having to periodically interrupt projects to respond to emergencies. The percent of mains activity completed by contractors in 2010 was 81 percent versus 2009 at 70 percent. 2010 unit costs ($56/metre) have dropped significantly from 2009 actuals ($72/metre) primarily due to the elimination of a secondary contractor in the Lower Mainland (with the highest pricing), regular reviews of contract pricing, a shift of work to contractor from FEU crews, change in geographical mix of work, and strengthening of the main extension estimating process. Offsetting these unit cost reducing factors have been several cost pressure factors including managing the demographic challenge (recruiting, training and outfitting apprentices to replace retiring workers), the rising cost of managing construction with a multitude of municipalities, inflationary increases in wages, vehicles, contracts and materials. Other variables impacting overall unit costs during this period are geographical location of main extension, travel times, pavement and traffic control requirements. Forecast unit costs reflect the shift of this type of work activity to the current two install contractor companies. 2012 and 2013 forecast unit costs are based on 2010 actuals and 2011 projection and reflect inflationary increases for the contractor workforces. The inflationary increase used for both 2012 and 2013 is 2 percent.

MAINS EXPENDITURES

The 2010 actuals and 2011 projected expenditures are considerably lower than the 2010-2011 approved amounts due to a combination of lower activity levels and lower unit costs driven by the factors cited in the respective sections above.

The new mains expenditures forecasts for 2012 and 2013 are $6.1 and $6.5 million respectively. Total new mains expenditures are largely variable and rise and fall with activity levels. The forecast activity levels of 105,395 meters in 2012 and 109,623 meters in 2013 are reflected in the aggregate expenditure requested. Experience with unit costs in 2010 with the two remaining install contractors who completed 81 percent of the work forms the basis for the forecast unit costs. The forecast unit costs when applied to the forecast activity level drive the overall new mains expenditure requirement. We believe these expenditures are prudent and reasonable in providing for distribution main extensions to serve new customers.

6.2.3.3 Services - Mainland

Forecast services activities, together with unit costs and capital expenditure levels are summarized in Table 6.2-15 and discussed in the sections that follow.

Table 6.2-15: Approved, Actual and Forecast Mainland Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	5,952	6,629	6,166	6,361	6,656	6,923
Gross Customer Additions	9,336	12,770	9,672	10,194	10,667	11,095
Ratio of Service Additions to Gross Customer Additions	0.78	0.73	0.78	0.72	0.72	0.72
Activities (risers or services)	7,303	9,382	7,566	7,337	7,677	7,985
Unit Costs ($ per service - riser)	2,016	$ 1,479	2,107	$ 1,523	$ 1,569	$ 1,616
Expenditures ($000's)	$ 14,722	$ 13,874	$ 15,940	$ 11,175	$ 12,044	$ 12,903

SERVICES ACTIVITY LEVELS

The 2012 and 2013 forecast level of services activity is derived directly from the gross customer additions forecast, as discussed in Section 4. Using the three year historical average (2008-2010), the ratio of Service Additions to Gross Customer Additions is 0.72. A three year historical average ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected service additions activity levels for 2011 are 7,337 services and are based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new service activity has been forecast at 7,677 and 7,985 services, respectively.

SERVICES UNIT COSTS

Aggregate (blended) service unit cost, which is the second consideration in establishing the forecast expenditure requirement for new services, is calculated by taking all services costs (including service header main) and dividing by the number of risers (services) installed.

The 2010 actual and 2011 projected blended service unit cost was lower than the approved unit costs in the 2010-2011 RRA which were based on 2009 year-end projections of $2,000 per service which in turn were based on Jan-May 2009 actuals which reflected a significant downturn in the economy and shifting of services work from contractors to the company workforce. The 2009 end of year actual unit cost of $1,769 reflected a recovery in activities in the latter half of 2009 and an improvement in unit costs.

The forecast unit costs for 2012 and 2013 reflect the most recent actual aggregate unit cost experience of 2010 and the 2011 forecast. Activity levels have risen from the lows of 2008 and 2009 and aggregate unit costs are at the lowest levels seen since 2006. The 2010 unit cost of $1,479 was lower than the average 2008-2009 services unit cost of $1,709. Unit costs in 2010 were driven down by changes in the workforce (utility versus contractors), optimal crew sizing, increased activity levels, strengthening of the estimation process, elimination of higher priced secondary contractor, change in the mix of services, changes in the geographical mix of the services and exclusion of training costs in the labour rates. In 2010, contractors completed 36 percent of this work versus 32 percent in 2009. The 2008-2009 unit costs reflected the addition of apprentices to crews to train for replacement of retiring employees, the downturn in the economy in late 2008, lower services activities in 2009, changes in the geographical mix of these services and changes in the mix of these service products. Forecast unit costs are based on 2011 projections and reflect inflationary increases for both Mainland and Contractor workforces and equipment. The inflationary increases projected are 3 percent for 2012 and 3 percent for 2013.

SERVICES EXPENDITURES

The 2010 actuals and 2011 projected expenditures are lower than the 2010-2011 approved amounts due primarily to considerably lower unit costs driven by the factors cited in the Services Unit Costs section above. The lower services expenditures related to unit cost reductions were partially offset by increased service expenditures due to the higher number of services installed over approved levels.

Service expenditures for 2012 and 2013 are forecast at $12.0 and $12.9 million, respectively. Total services expenditures are largely variable and rise and fall with activity levels. The forecast activity levels, together with unit cost history adjusted for inflation form the basis for the aggregate expenditure requested. We believe these expenditures are prudent and reasonable in providing service products including service header mains to service new customers.

6.2.3.4 New Meters – Mainland

The discussion of new meter expenditures is included in Section 6.2.2.3.

In Table 6.2-15 above, the New Meters expenditures forecast for 2012 and 2013 is $2.0 million and $2.1 million respectively. Meters expenditures are variable and rise and fall with customer additions activity levels.

6.2.3.5 Biomethane/NGV - Mainland

BIOMETHANE

Capital invested in interconnection facilities and upgrader equipment for Biomethane projects during the test period is forecast to be $3.1 million and $3.6 million in 2012 and 2013 respectively. Further detail on this capital investment is provided in Appendix J.

NGV

Capital invested in NGV fueling assets, subject to approval of the NGV Application presently before the Commission, is forecast to be $4 million in 2012 and $4.8 million in 2013. These projects will be accompanied by contracts that provide for their forecast incremental costs of service to be recovered through dedicated take-or-pay incremental revenues from the incremental NGV fueling customers. Further detail on this capital investment is provided in Appendix I.

6.2.3.6 Vancouver Island Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Vancouver Island are summarized in Table 6.2-16 below.

Table 6.2-16: Approved, Actual and Forecast Vancouver Island Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	2,725	1,836	2,966	2,553	2,757	2,922
New Customer Services	5,940	5,309	6,459	4,517	4,926	5,270
New Customer Meters	540	430	582	440	480	513
	9,206	**7,575**	**10,006**	**7,510**	**8,163**	**8,705**

6.2.3.7 Mains – Vancouver Island

Forecast new mains activity, together with unit costs and capital expenditure levels are summarized in Table 6.2-17 below.

Table 6.2-17: Approved, Actual and Forecast Vancouver Island Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	30,116	18,282	31,610	24,927	26,393	27,415
Unit Costs ($/meter)	$ 90	$ 100	$ 94	$ 102	$ 104	$ 107
Expenditures ($000's)	$ 2,725	$ 1,836	$ 2,966	$ 2,553	$ 2,757	$ 2,922

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are described in the following three sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year

(2008-2010) historical ratio of 0.81 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 12 metres of new main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected new mains activity levels for 2011 are 24,927 metres based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new mains activity has been forecast at 26,393 and 27,415 metres, respectively.

MAINS UNIT COSTS

The forecast unit costs for 2012 and 2013 reflect the unit cost experience of 2010 inflated by 2 percent annually. The 2010 activity levels declined 26 percent from 2009 levels which contributed to economy of scale unit cost pressures when compared to 2010 approved activity levels and unit cost. Due to the declining service activity levels, on a percentage basis, the Vancouver Island mains work has seen a slight shift back to the company workforce from the install contractors although the total amount of new mains work installed by the company's own workforce has remained unchanged in 2010 from 2009. The percent of mains activity completed by contractors in 2010 was 80 percent versus 87 percent in 2009 and 97 percent in 2008. Vancouver Island maintains company workforce levels sufficient to respond to emergencies and consequently, Vancouver Island own workforce unit costs are historically higher than contractors due to having to periodically interrupt projects to respond to emergencies. 2010 unit costs ($100/metre) have dropped from 2009 actuals ($105/metre) due to changes in contract pricing, exclusion of training costs in company labour rates and strengthening of the main extension estimating process. Other variables impacting overall unit costs are geographical location of main extension and the corresponding municipal, pavement, and traffic control requirements.

Forecast unit costs reflect a significant component of new mains work activity being assigned to the install contractor as our crews typically have sufficient levels of emergencies, new and conversion service activity to limit assignments to the lengthier more complex main jobs. 2012 and 2013 forecast unit costs are based on 2010 actuals and 2011 projection and reflect inflationary increases for the contractor workforces. The inflationary increase used for both 2012 and 2013 is 2 percent.

MAINS EXPENDITURES

The 2010 actuals and 2011 projected expenditures are lower than the 2010-2011 approved amounts due primarily to lower activity levels. Higher actual unit costs in 2010 versus approved unit costs driven by the factors cited above partially offset the reduction in expenditures due to lower activities.

The new mains expenditures forecasts for 2012 and 2013 are $2.8 million and $2.9 million respectively. Total new mains expenditures are largely variable and rise and fall with activity levels. The forecast activity levels of 26,393 meters in 2012 and 27,415 meters in 2013 are reflected in the aggregate expenditure requested. Experience with unit costs in 2010 with the current install contractor who completed 80 percent of this work, form the basis for the forecast unit costs. The forecast unit costs when applied to the forecast activity level drive the overall new mains expenditure requirement. We believe these expenditures are prudent and reasonable in providing for distribution main extensions to serve new customers.

6.2.3.8 Services – Vancouver Island

Forecast services together with unit costs and capital expenditure levels are summarized in Table 6.2-18 and discussed in the sections that follow.

Table 6.2-18: Approved, Actual and Forecast Vancouver Island Services Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Net Customer Additions	2320	2,725	2430	2,415	2,557	2,656
Gross Customer Additions	2460	2,940	2582	2,564	2,714	2,820
Ratio of Service Additions to Gross Customer Additions	0.78	0.85	0.78	0.81	0.81	0.81
Activities (risers or services)	1,922	2,501	2,017	2,066	2,187	2,272
Unit Costs ($ per service - riser)	$ 3,091	$ 2,123	$ 3,202	$ 2,186	$ 2,252	$ 2,320
Expenditures ($000's)	$ 5,940	$ 5,309	$ 6,459	$ 4,517	$ 4,926	$ 5,270

SERVICES ACTIVITY LEVELS

The 2012 and 2013 forecast level of services activity is derived directly from the gross customer additions forecast, as discussed in Section 4. Using the current three year historical average (2008-2010), the ratio of Service Additions to Gross Customer Additions calculated is 0.81. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected service additions activity levels for 2011 are 2,066 services and are based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new service activity has been forecast at 2,187 and 2,272 services, respectively.

SERVICES UNIT COSTS

Aggregate (blended) service unit cost, which is the second consideration in establishing the forecast expenditure requirement for new services, is calculated by taking all services costs (including service header main) and dividing by the number of risers (services) installed.

The 2010 actual and 2011 projected blended service unit cost are lower than the approved unit costs in the 2010-2011 RRA primarily due to refinements made to the estimating process for exception type service jobs such as conversion services. The 2010-2011 RRA unit cost amounts were based on 2009 year-end projections which in turn were based on Jan-May 2009 actuals which reflected a standard cost estimating practice for conversion services, a significant downturn in the economy and shifting of services work from contractors to the company workforce. The 2009 end of year actual unit cost of $2,424 reflected a recovery in activities in the latter half of 2009 and an improvement in unit costs at least partially due to the elimination of services that previously met the economic test under the standard geo-code estimating methodology. One of the refinements made to the estimating process was to introduce job specific estimating for conversion services as these types of installations typically attract irregular costs being located in well-developed established areas.

The forecast unit costs for 2012 and 2013 reflect the most recent actual aggregate unit cost experience of 2010 and the 2011 forecast. Forecast unit costs are based on 2011 projections and reflect inflationary increases for both Vancouver Island and Contractor workforces and equipment. The inflationary increases projected are 3 percent for 2012 and 3 percent for 2013.

SERVICES EXPENDITURES

The 2010 actuals and 2011 projected expenditures are lower than the 2010-2011 approved amounts due primarily to considerably lower unit costs driven by the factors cited in the Services Unit Costs section above. The lower services expenditures related to unit cost reductions were partially offset by increased service expenditures due to the higher number of services installed compared to approved levels.

Service expenditures for 2012 and 2013 are forecast at $4.9 million and $5.3 million respectively. Total services expenditures are largely variable and rise and fall with activity levels. The forecast activity levels, together with recent unit cost history adjusted for inflation form the basis for the aggregate expenditure requested. We believe these expenditures are prudent and reasonable in providing services and service header mains to service new customers.

6.2.3.9 New Meters –Vancouver Island

The discussion of new meter expenditures is included in Section 6.2.2.8.

In Table 6.2-16 above, the New Meters expenditures forecast for 2012 and 2013 is $0.5 million. Meters expenditures are variable and rise and fall with customer additions activity levels.

6.2.3.10 Whistler Growth Capital

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Whistler are summarized in Table 6.2-19 below.

Table 6.2-19: Approved, Actual and Forecast Whistler Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	51	219	35	218	223	227
New Customer Services	97	122	68	48	52	53
New Customer Meters	14	3	9	4	5	5
	163	**344**	**112**	**270**	**279**	**285**

Forecast mains activity levels, unit costs and resulting capital expenditure are difficult to forecast in Whistler due to the small volumes and wide year over year fluctuations. For 2009 and 2010 the average metres of main installed was 1,800 metres and we have assumed a similar level of activity for 2012-2013. Unit costs are generally higher in Whistler than in the Mainland and Vancouver Island as the install contractor completing mains and services work is located outside the Whistler service territory and includes a crew mobilization/travel charge in rates. Depending on the volume of activity the mobilization charge can be spread across one job or many. Install conditions are generally more difficult in Whistler than the average provincial conditions due to the rockier landscape. For 2012-2013, we have assumed a unit cost of 2010 actuals inflated by 2 percent per annum to reflect expected contractor pricing changes.

Service activity levels are derived from the forecast for gross customer additions and are generally quite low compared to other service areas. The 2010 ratio of service additions to gross customer additions is .90 and this ratio was applied to the 2011 projection as well as the 2012 and 2013 forecasts to establish activity levels. Service unit costs are generally higher in Whistler than both Vancouver Island and Mainland due to rockier conditions and higher install contractor pricing which includes a contractor crew mobilization charge being applied across a few service jobs. Generally speaking, contractor charges for services in Whistler are approximately $2,600 with conditions, length of service and number of service jobs completed during the same crew mobilization week being primary factors in determining costs. The 2012 and 2013 forecast unit costs are based on 2011 projected unit costs inflated 3 percent per annum. Whistler contract pricing is reviewed regularly and expectations are that increased fuel prices will drive above normal contractor inflation for services work.

Meter activity levels are based on meters required to service new customers and are driven by the number of customer additions. Meter unit cost is a blended amount of residential, commercial and industrial meters and forecast amounts for 2012 and 2013 reflect the most recent actual experience of 2010 with natural gas meters.

6.2.3.11 Fort Nelson Growth Capital

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Whistler are summarized in Table 6.2-20 below.

Table 6.2-20: Approved, Actual and Forecast Fort Nelson Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	11	23	11	11	12	12
New Customer Services	22	32	13	48	47	53
New Customer Meters	4	10	5	6	6	6
	37	**65**	**29**	**65**	**65**	**71**

Mains activity levels in Fort Nelson, are generally low and fluctuate widely from year to year depending on the local economy. Unit costs are difficult to forecast due to the small volume of activity. No major extensions are foreseen at this time. As with the other Utilities, all proposed main extensions are scrutinized through the main extension review test to determine if they are economic. For forecasting purposes the 2012 and 2013 expenditure was based on the 2011 projection inflated.

Service activity levels are driven by the forecast for gross customer additions which is projected to increase from 2010. For the 2011 projection, the ratio of service additions to gross customer additions is projected to be 1.0 and this ratio was applied to the 2012 and 2013 forecasts to establish activity levels. For every forecast gross customer addition, one service addition has been forecast.

Service unit costs (inclusive of service header mains) are reflective of services installed by the local crew. The 2010 unit cost experience ($1,257 per service), although based on very few services, is typical of expected unit costs and is the basis for the 2011 projection. The 2012 and 2013 forecast unit costs are based on 2011 projected unit costs inflated at 3 percent per annum. Forecast services expenditures are simply the forecast service activity volumes multiplied by the forecast unit costs.

Forecast meter expenditures are required for new activities. There is minimal activity expected in 2011, and 2012 and 2013 forecasts are based on 2011 projections. The 2010 actuals included one upgrade/alteration on a larger set for $5 thousand which is not expected in 2011.

We believe the 2012-2013 forecast Growth Capital expenditures for Fort Nelson are reasonable. They are similar to the 2010 actual expenditure level and local circumstances have not materially changed.

6.2.3.12 Growth Capital Summary

The forecasts for Growth Capital expenditures for 2012-13 have been developed in a manner consistent with past practice and based on recent historical data, utilizing projected customer additions and current unit costs escalated by inflation. The forecast of $35.7 million for 2012 and

$37.9 million for 2013 represent the level of this type of investment required to provide safe, reliable and efficient service to new and existing customers of the FortisBC Energy Utilities.

6.2.4 FACILITIES AND EQUIPMENT CAPITAL

Facilities and Equipment Capital expenditures include the acquisition or leasing of land, station buildings, facilities equipment, telecommunications infrastructure, specialized tools and equipment, and radio system upgrades. Technological improvements tend to drive changes in tools, equipment, radios and furniture.

6.2.4.1 Facilities and Equipment Capital – Mainland

The approved, actual, projected, and forecast capital expenditures for the Mainland Facilities and Equipment are summarized in Table 6.2-21 below.

Table 6.2-21: Approved, Actual and Forecast Mainland Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	2,973	3,434	2,634	2,664	3,310	2,930
Facilities	3,737	4,177	4,212	4,138	8,424	4,124
	6,710	**7,611**	**6,845**	**6,802**	**11,734**	**7,054**

EQUIPMENT

The forecast expenditures of $3.3 million and $2.9 million in 2012 and 2013 are generally consistent with historical spending, although higher than normal spending was experienced in 2010, when expenditures were $461 thousand higher than approved. This was due to a conversion of some Company vehicles to natural gas, and to the acquisition of CNG refuelling equipment located on FEI's sites in Burnaby and Surrey, which provide fueling service to the Company's fleet.

An increase of $150 thousand in equipment expenditure is required in 2012 for the integration of the radio network system. In an emergency situation, it is critical that the utilities can broadcast "one too many" radio communications to ensure the initial response and the subsequent continuation of service is done in a manner that is timely, cost effective, and above all, preserves the safety of both the public and employees. As such, the Company continues to operate a private radio network throughout its coastal and interior service territories.

The remaining increase in 2012 is primarily due to cyclical spending on tools and equipment replacement, additional requirements for in-ditch inspection equipment, and a one-time purchase of inspection kits.

FACILITIES

Facilities ensures business requests are suitable for the business and built to meet company standards, building code and regulations and provides a long term view of the facilities.

In 2010, Facilities expenditures were $440 thousand higher than approved as a result of the project to create additional surface parking at Surrey Operations being delayed from 2009, non forecast Salmon Arm Muster renovations and a storage addition for the Langley Compressor station that was originally budgeted under Transmission Sustainment Capital.

The increased pressure to the Surrey site, both parking and office space, will continue in 2012 as forecast employees and project consultants at this location continues to rise. Facilities is planning on increasing the densification of the Surrey Operations site and increasing the workstation count. This densification will require the purchase of new additional furniture systems to build out new workstations and alter existing workstations. The furniture costs are estimated at $1.5 million. Densification will eliminate the requirement for additional O&M of over $1.7 million per year for a leased facility and will maintain the business groups at one facility to support efficiency and collaboration within the groups.

In 2012, Facilities also proposes to purchase land for the North Vancouver Muster for an estimated $2 million. This estimate is based on the requirement of approximately .5 acre at the current market rate of $85 square foot. The muster is currently leased and, due to an expansion for the Landlord, we will be forced out and not able to operate from this site. This site is a critical for the Operations department as it provides operational support for the North and West Vancouver areas and is on the north side of the Burrard Inlet to ensure resources are always available for this area in the event of an emergency. The Landlord has provided reasonable timelines for their expansion and Facilities has been exploring alternatives for two years with no success due to the limited industrial real estate market.

Other projects within the 2012 and 2013 budget year are smaller projects that range from storage improvements, building additions, HVAC upgrades, security upgrades and office furniture and equipment purchases. In particular, there is an increase of approximately $1.4 million in 2012 due to the Penticton Meter Shop modification and Langley Compressor Station Muster addition. Modifications are required to the Penticton Meter Shop as a result of a regulatory requirement change to the standards for meter sampling. The change will result in an increased sample base and product movement through the Penticton Meter Shop. The Langley Compressor Muster Station addition will provide a mustering facility for Operations at this station which will allow personnel to have access to tools and equipment to perform maintenance and inventory. The existing Langley muster cannot accommodate all personnel.

6.2.4.2 Facilities and Equipment Capital – Vancouver Island

The approved, actual, projected, and forecast capital expenditures for Vancouver Island Facilities and Equipment are summarized in Table 6.2-22 below.

Table 6.2-22: Approved, Actual and Forecast Vancouver Island Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	1,615	1,181	1,500	1,391	3,073	3,591
Facilities	291	400	141	343	439	616
	1,906	**1,581**	**1,642**	**1,734**	**3,512**	**4,207**

The projected expenditures for Facilities and Equipment for 2012 and 2013 are $3.5 million and $4.2 million respectively.

These expenditures include purchases for tools and equipment, office furniture and equipment and facilities. The increase in expenditure for tools and equipment in 2012 and 2013 is due to the expansion of the Companies' radio system to the Vancouver Island region. Maintaining the emergency response capability has required the Companies to expand their current private radio communications network. Currently, Vancouver Island attempts to address this need through the use of an independent third party solution. This network is limited in that the service coverage is inadequate and the network is isolated from the remainder of the Companies' service areas. Therefore, parts of this region carry a much greater risk of not having adequate emergency communications capability compared to the remainder of the our service areas and will have limited ability to receive or offer support with other regions in the event of a major emergency. Compounding this concern is the fact that this service is provided over a public network which can become overly congested during major emergencies, preventing a safe and timely response within the impacted area. As such, in order for Vancouver Island to ensure effective emergency communications within the region, FEU's private network will need to be expanded to include the Vancouver Island service territory. Expansion of FEU's existing private radio network will allow the Company to address the limitations described above while leveraging the experienced operating group already in place. Expenditures for the radio system replacement is anticipated to be $1.8 million in 2012 and $2.2 million in 2013.

The projected expenditures for the improvement or replacement of structures, office furniture and equipment replacement in 2012 and 2013 are $436 thousand and $490 thousand respectively.

6.2.4.3 Facilities and Equipment Capital – Whistler

The approved, actual, projected, and forecast capital expenditures for Whistler Facilities and Equipment are summarized in Table 6.2-23 below.

Table 6.2-23: Approved, Actual and Forecast Whistler Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	18	5	17	17	20	60
Facilities	53	15	25	25	290	13
	71	**20**	**42**	**42**	**310**	**73**

Expenditures for Equipment are anticipated to be $20 thousand and $60 thousand in 2012 and 2013, respectively. $50 thousand is required in 2013 to replace an existing Bobcat vehicle in Whistler. These vehicles typically need to be replaced every four to five years; therefore, funding is only required on a cyclical basis.

With the planned disposition of the propane plant sites, Facilities reduced spending in 2010 by $40 thousand while a site assessment was completed for the remaining facilities. As the remaining sites have no storage, a new storage shed is proposed for 2012 to provide secure and dry covered storage for tools and equipment used to support the local operations to deliver natural gas. The 2012 forecast for this item is $290 thousand.

6.2.4.4 Facilities and Equipment Capital – Fort Nelson

The approved, actual, projected, and forecast capital expenditures for Fort Nelson Facilities and Equipment are summarized in Table 6.2-24 below.

Table 6.2-24: Approved, Actual and Forecast Fort Nelson Facilities & Equipment Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Other						
Equipment	-	-	8	8	10	10
Facilities	-	-	-	-	129	-
	-	**-**	**8**	**8**	**139**	**10**

Facilities require $129 thousand for expenditures for the Fort Nelson area in 2012 to provide water and sewer connection for our office to the municipality's systems. The municipality of Fort

Nelson is currently developing the area around our office which will bring the water and sewer services to our facility. It is beneficial for the Company to connect to these services and not rely on a septic field and well water as it reduces future replacement costs of the existing septic system and well water and minimizes risk around potential water contamination. In addition, there will be fencing changes and a concrete apron addition will be added to one of the storage buildings to improve accessibility. The Company believes these costs are prudent and valuable for the future.

6.2.4.5 Summary of Facilities and Equipment Capital

Facilities and Equipment Capital has been forecast based on known and anticipated projects. These expenditures are required to meet the ongoing business requirements of the Utilities.

6.2.5 IT EXPENDITURES

The approved, actual, projected, and forecast capital expenditures for the FortisBC Energy Utilities' Category C IT capital are summarized in Table 6.2-25 below.

Table 6.2-25: Approved, Actual and Forecast IT Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
IT Capital - Mainland	16,000	12,418	16,000	16,000	18,000	18,000
IT Capital - Vancouver Island	1,500	1,473	1,500	1,500	2,000	2,000
IT Capital - Total	17,500	13,891	17,500	17,500	20,000	20,000

The 2010 actual amount of $13.9 million for both Vancouver Island and the Mainland in 2010 against the budget of $17.5 was primarily due to the approval of the Customer Care Enhancement (CCE) CPCN which refocused key IT and business resources that otherwise would have been allocated to other initiatives. At the time of budget planning, this CPCN was not yet approved therefore the budget was created assuming access to all required resources. Additionally, several key projects had their planned spend profile deferred between fiscal year 2010 and 2011 due to unplanned competing demands on scarce business resources and prolonged vendor negotiations. 2011 spend is projected to be $17.5 million based on the rebaselined plan factoring in CCE and maximizing the available resources.

In 2012 and 2013, IT expenditures are forecast to be $20 million annually, which will allow for the replacement, acquisition, and implementation of IT hardware, software, and related infrastructure.

The following will describe how IT expenditures are allocated to Vancouver Island, the key drivers of IT expenditures, how the IT project portfolio is developed and the basis for the 2012-2013 forecast amounts.

ALLOCATION TO VANCOUVER ISLAND

As detailed in the previous Application, IT development and support has been centralized within the Mainland utility. The vast majority of capital expenditures are made in support of all of the FortisBC Energy Utilities regulated operating entities. It remains the case in this application that the costs of these initiatives will continue to be initially captured within the Mainland utility and then allocated to Vancouver Island where Vancouver Island utilizes those technology investments. The allocations are predicated on the nature of the expenditure. If the capital expenditure is to support a new business process or enhance an existing one that is followed by both utilities, then the allocation is based on employee distribution. This results in Vancouver Island being allocated ten percent of the overall capital costs. This allocation is also true for any initiatives that are driven by productivity improvements of investments made to shared infrastructure such as security, server upgrades, e-mail services, etc. In cases where the capital expenditure is specifically in support of Vancouver Island, these are direct costs with no allocation. This is the case with desktop and printer refresh initiatives. In cases where Vancouver Island is not a beneficiary of the outcome of the expenditure, there is no allocation. This was the case with the residential and commercial unbundling programs implemented in the Mainland utility.

KEY DRIVERS

The requirements for IT expenditures are categorized into three areas:

- Introducing or enhancing new capabilities in individual business units or the enterprise;
- Technology sustainment and upgrading; and
- Security / risk mitigation.

A key driver of IT capital expenditures is changing business process needs. The operating departments within the Company continually seek to identify more efficient or effective processes as well as to permit the Company to preserve efficiencies that have been attained. As a result, investments in information technologies are required. In addition, IT capital expenditures are made to enable the operating departments to comply with changing regulations and external requirements that demand compliance.

A second requirement for IT expenditures is the need to sustain and upgrade hardware and software. Keeping up with evolving technologies is a challenge for all companies as the frequent introduction of new infrastructure and new application versions have become commonplace throughout the IT industry. On occasion, the turnaround from new to discontinued application versions can be as short as 18 months. Larger application vendors (i.e. GE Smallworld and SAP) have scheduled version updates that incorporate new changes and additional functionality to the application, incorporate correction patches into the core system and take advantage of improvements in infrastructure. Many software and hardware vendors typically abandon older versions and withdraw support as their new version becomes available. Consequently, continuous sustainment investments must be made to replace these older applications and technologies. This sustainment cycle also requires the upgrading and replacement of desktop computer technologies in order to operate more advanced versions of the software applications. The establishment of an "Evergreening" program has enabled us to follow a consistent and predictable approach to ensuring core infrastructure and applications are reasonably current in today's ever changing version landscape, optimizing the usage the existing assets and then replacing them before they start to break down which would result in costly maintenance repairs and lost productivity.

The focus on IT security has increased steadily. A dramatic shift in security threats began early in 2001. This is primarily due to the increased use of Internet e-mail functionality and the escalating threat of external hackers. These security threats have grown to exploit weaknesses in all areas of network and software applications. The increased use of the Internet to support business processes requires additional investment in the protection of those processes and associated data. IT security must continue to be implemented with a depth model that uses many layers of differing protection but still offers the capability to support business requirements. With the disaster recovery site operational, IT is better equipped to support the breadth of the Disaster Recovery Plan required for business continuity; however continued investment must be made to ensure the relevancy of the information slated for disaster recovery considering the constant change in the Company's applications and systems.

The demand for IT capital investment pursuant to the categories above is significant. It is the IT department's experience that this demand continues to outpace the Company's capacity to execute. It is also the Company's experience that not all projects that are implemented by the end of any year are identified during the prior year's budgeting process. The capability of the business units to invest resources required to successfully implement new solutions must be balanced against operational demands.

IT PROJECT PORTFOLIO DEVELOPMENT

In order to mitigate the issues above, the Company implemented in 2010 a well established methodology known as IT Project Portfolio Management (PPM). This methodology is a recognized discipline for managing IT Project portfolios that facilitates the evaluation, prioritization and coordination of the requirements of the various operating business units and technology, thus enabling more effective capital investment decisions.

The Company's PPM provides a standard framework to evaluate projects allowing for the comparison and selection of competing IT investment options. Projects must be aligned to one or more of the Company's strategic goals, and each project is required to demonstrate how it supports the achievement of organizational goals and priorities. PPM compares and prioritizes potential IT project investments based on the project's value contribution to the organization's goals, irrespective of where the initiative originated. Those projects with the greatest contribution and alignment will receive highest priority. The priority of each project guides the financial and resource allocation for the portfolio. Prioritization ideally assures projects with the greatest value to the Company will be considered first when allocating finite resources. PPM ultimately drives the establishment of the IT Project Portfolio which must be reviewed and accepted by the Utility Operating Committee Capital Management group consisting of the key representatives from IT, Finance, Regulatory, Distribution, Transmission, Marketing, and Engineering Services. This activity takes place annually following the corporate budgeting process and in advance of initiation of the targeted fiscal year. Prior to execution, all approved IT Project Portfolio projects must still acquire formal authorization for capital investment through written justification (business casing) which reconfirms the business value of undertaking the project and validates the assumptions made in the initial establishment of the IT Project Portfolio.

2012 AND 2013 FORECASTS

The Company is forecasting an increase of $2.0 million for the Mainland and $500 thousand for Vancouver Island for 2012 from the 2011 total of $16.0 million and $1.5 million respectively, with 2013 held at that level. This increase is based on enabling several robust technology roadmaps created in 2010 and 2011 in addition to satisfying pent-up demand from restrictions on the execution of several IT projects other than the CCE CPCN. Effective execution of this increased forecast will be managed through the employment of PPM, management of inter-project dependencies and risk mitigation within the IT Project Portfolio and the optimal usage of IT and business resources freed up from the cessation of the CCE CPCN. For projects that require significant business involvement, the business must prioritize between IT project commitments and other business imperatives. Over the years, the Company has invested time and effort on technology that enables operational efficiencies and the integration of business processes spanning multiple business units. Consequently, the IT Project Portfolio management team must work to ensure that all affected groups are coordinated and have the same ability to commit resources to projects that impact them all.

The capital request for IT investment is forecast at an amount in 2012 and 2013 that FEU believes is the appropriate amount that can prudently be executed while meeting the top priorities of the business. The incremental $2.0 million from 2011 to a total of $18 million for the in each of 2012 and 2013 reflects the costs anticipated to ensure a balanced IT Project Portfolio that will address the requirements of technology sustainment, security and risk mitigation and meet the priority demands of the Company's further IT enablement.

6.2.6 CONTRIBUTIONS IN AID OF CONSTRUCTION

6.2.6.1 CIAC - Mainland

The table below summarizes Mainland's anticipated CIAC recoveries for 2012-2013.

Table 6.2-26: Approved, Actual and Forecast Mainland Contributions in Aid of Construction

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital	936	512	(763)	(1,261)	(1,319)	(1,372)
Sustainment Capital	(4,700)	(4,350)	(2,900)	(4,966)	(3,750)	(3,750)
CPCN	-	(84)	-	-	-	-
Retirements					(271)	(277)
Total	**(3,764)**	**(3,922)**	**(3,663)**	**(6,227)**	**(5,341)**	**(5,399)**

CIAC for 2012 and 2013 are based on recoveries for the forecast customer additions and anticipated receivable work.

In total, CIAC are forecast at $5.3 million in 2012 and $5.4 million in 2013.

For Growth Capital, the 2010 Approved and Actual includes the transfer of the $1.443 million balance in the Deferred Service Line Installation Fee account to CIAC on January 1, 2010, as approved by Commission Order No. G-141-09.

CIAC for Sustainment Capital are anticipated to be $3.7 million in 2012 and 2013. The recoveries in this category were budgeted based on the anticipated receivable work for third party alterations and historical levels of receivable work for Transmission crossing replacements and identified recoverable projects. Higher CIAC is anticipated for 2012 and 2013 due to an increase in receivable work on third party alterations, expected especially as a result of announcements by municipalities to increase infrastructure renewal, for the forecast periods.

6.2.6.2 CIAC - Vancouver Island

The table below summarizes Vancouver Island's anticipated CIAC recoveries for 2012-2013.

Table 6.2-27: Approved, Actual and Forecast Vancouver Island Contributions in Aid of Construction

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital	(117)	(140)	(123)	(122)	(130)	(135)
Sustainment Capital	(310)	(218)	(310)	(350)	(281)	(281)
CPCN	-	-	-	-	-	-
Retirements					(15)	(15)
Total	**(427)**	**(358)**	**(433)**	**(472)**	**(426)**	**(431)**

CIAC for 2012 and 2013 are based on recoveries for the projected customer additions and anticipated receivable work.

CIAC of $426 thousand and $431 thousand for 2012 and 2013 respectively are consistent with average contributions over the 2010 – 2011 period.

6.2.6.3 CIAC - Whistler

Whistler does not anticipate any contributions for the 2012-2013 forecast period.

6.2.6.4 CIAC - Fort Nelson

Fort Nelson does not anticipate any contributions for 2012-2013 forecast period.

6.2.7 CPCNs

Section 45(1) of the UCA requires that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the Commission a CPCN approving the construction or operation. Section 46(1) of the UCA requires an application for a CPCN be filed with Commission.

As agreed to in the 2010-2011 RRAs for the Mainland and Vancouver Island, large capital expenditures over $5 million (excluding AFUDC) qualify for the CPCN application process. This threshold has been in place since 2003. The 2010 Certificates of Public Convenience and Necessity Application Guidelines, issued March 18, 2010, provide general guidance regarding the Commission's expectations of the information that should be included in a CPCN Application.

As CPCNs are approved through a separate process, we have not included in this RRA the capital expenditures related to CPCNs that are anticipated but have not yet been approved. CPCNs that have been approved and are forecast to go into service during the test years are included in rate base in this RRA.

The sections below discuss both approved and anticipated CPCNs for the Mainland and Vancouver Island. The section on anticipated CPCNs is provided for information only, as these projects do not affect the forecasts included in this RRA.

6.2.7.1 Mainland CPCNs – Approved Projects

FRASER RIVER CROSSING PROJECT

In November of 2008, FEI filed an application for a CPCN for the Fraser River South Arm Crossing Upgrade Project as part of the Coastal Transmission System, consisting of a new crossing using horizontal directional drill technology to replace the 24 inch and the 20 inch since there is a risk of a major seismic event. On March 12, 2009, the Commission granted a CPCN for the Project by Order No. C-2-09. Current pipeline in-service dates are estimated at the third quarter of 2011, approximately 20 months later than originally planned. At this time the estimated cost at completion for the Project is $36.3 million including AFUDC based on completion of the associated restoration work in 2011 and excludes a settlement between the contractor and FEI in the event that the contractor submits any extra-ordinary claims. The project has been included in rate base in October of 2011 based on the current timeline to completion.

CUSTOMER CARE ENHANCEMENT PROJECT

In June of 2009, FEI filed an application for a CPCN for the CCE Project and on February 26, 2010, the Commission granted approval by way of Order No. C-1-10. This approval was subject to a cost sharing formula, wherein if the final cost of the Project is greater than 10 percent above or greater than 10 percent below $115.5 million including AFUDC, the additional costs or savings outside that +/- 10 percent band will be shared equally between the Company and its ratepayers.

The CCE Project is well underway and the forecast cost of the project including AFUDC remains at the approved level of $115.5 million including AFUDC (of which $74.7 million corresponds to capital spend and $40.8 million to deferred O&M). The scheduled date that the FEU expects to go live with the new system continues to be January 1st, 2012. Overall good progress has been made to date, with the completion of the detailed system design for the SAP CIS platform. Currently the Project team is engaged in the configuration and development of the reports and interfaces, unit testing and integration testing of the new system together with documentation of the business process designs. In addition, development of recruitment plans, training plans, training materials and end user documentation is ongoing to ensure the Contact Centres and back office operations are staffed with knowledgeable and skilled employees. Furthermore, two new facilities, one in Burnaby and the other in Prince George, are currently being prepared to house the new operations.

TILBURY LAND PROPERTY PURCHASE

In October of 2009, FEI filed a CPCN application for the acquisition of the Tilbury Property, immediately adjacent to the Tilbury LNG Facility, at a cost close to $16 million. On April 27, 2010, the Commission granted a CPCN for the Property by Order No C-2-10, with a condition that generally results in the amount of land to be added to rate base January 1, 2012 being reduced by that portion of the Property to be subdivided and sold. As a result, of the total Property purchase price, $14.2 million will be added to rate base January 1, 2012.

KOOTENAY RIVER CROSSING (SHOREACRES) PROJECT

In July of 2010, FEI field an application for a CPCN to replace the aerial pipeline crossing of the Kootenay River located near the community of Shoreacres with a new crossing by means of a horizontal directional drill as part of the Interior Transmission System. On November 10, 2010, the Commission granted a CPCN for the Project by Order No. C-9-10 for an estimated $8.3 million including AFUDC and with a projected in service date of October, 2011. Current estimates remain at the CPCN estimates for both project costs and in service date.

6.2.7.2 Mainland CPCNs - Anticipated Projects

HUNTINGDON STATION BYPASS

FEI's Huntingdon Control Station, located on the Canada/US border south of Abbotsford, controls the supply of natural gas to the majority of customers in the Lower Mainland and all of the customers in Whistler, Squamish, the Sunshine Coast, and Vancouver Island. In total, approximately 660,000 customers depend on Huntingdon for their gas supply. The Huntingdon Control Station, originally commissioned in 1956 has been continually operated, upgraded and maintained to ensure the station remains fit for service. Through operational experience and risk assessments, FEI identified the station as a potential "single point of failure," meaning that the failure of the station would cause the complete outage of the entire gas system. This failure event could be caused by equipment failures, natural hazards, vandalism, or failures of adjacent interconnected midstream pipelines and facilities. The risk of a failure event due to such an incident is amplified by a lack of redundancy within certain parts of the station.

In order to ensure reliable gas supply to the approximately 660,000 FEI customers who depend on Huntingdon, FEI proposes constructing a bypass pipeline around Huntingdon Station and the associated interconnection facilities that will provide redundancy to the overall system and mitigate the impact of a major incident at Huntingdon from any of the failure scenarios listed above. The Company plans to submit a CPCN application in the second quarter of 2011 for the installation of the station bypass, to be completed before the 2012/13 winter season. The current project cost is estimated at $25 - $30 million.

OKANAGAN REINFORCEMENT PROJECT

Based on the 2011 core market demand forecast, the Interior Transmission System is anticipated to face system capacity shortfall by 2017. Currently, three resource options are being considered: phased pipeline looping from Penticton towards Kelowna in conjunction with increased compression at Kitchener-B Compressor Station at a budgetary estimate of $42 million and $20 million respectively; Phased pipeline looping from Savona at a budgetary estimate of $30 million; or LNG peaking storage facility in North Okanagan at a budgetary estimate of $131 million. Depending on the option yet to be chosen, the CPCN application will be filed with the Commission as early as 2014.

6.2.7.3 Vancouver Island - Approved Projects

MOUNT HAYES LNG STORAGE FACILITY PROJECT

In June of 2007, FEVI filed an application for a CPCN for the Mt. Hayes LNG Storage Facility Project, including construction and ownership of an LNG peak-shaving storage facility at Mt. Hayes near Ladysmith, and various associated facilities to connect the LNG Storage Facility to Vancouver Island's natural gas transmission system. On November 15, 2007, the Commission granted a CPCN for the project by Order No. C-9-07. Total capital costs were approved for $193.3 million (excluding AFUDC). On-site construction is complete and commissioning is currently underway with planned completion and turn-over to FEVI in May 2011, and the Facility is expected to begin-service for the winter of 2011/12. The Project is on time and on budget; costs of $213.0 million including AFUDC have been included in FEVI's rate base in May 2011.

VICTORIA REGIONAL OPERATIONS CENTRE PROJECT

In October of 2010, FEVI filed an application for a CPCN seeking approval to acquire property and construct a new regional operations centre, replacing its existing leased facility. In January 2011, the Commission issued Order No. C-1-11 granting conditional approval for the acquisition of the property and deferred approval for construction until completion and review of a staffing report. FEVI filed the required report on February 28, 2011. On March 23, 2011 the Commission issued Order No. C-6-11 granting approval to construct the Victoria Regional Operations Centre. The total project capital cost is estimated at $13.8 million including AFUDC. Purchase of the property has completed with construction starting in late fall of 2011. Completion of the project is expected in October 2012.

6.2.8 CONCLUSION

The proposed 2012 - 2013 capital forecast reflects the appropriate level of capital expenditures needed to ensure the safety and reliability of the gas distribution system and provide service to new and existing customers. The FortisBC Energy Utilities' believe the forecast capital costs are prudent and required to meet the evolving needs of our customers and shareholder.

6.3 Rate Base Deferral Accounts

The Utilities have considered the following factors with respect to continuing existing deferral accounts and seeking deferral account treatment in different matters:

- Maintain those previously approved accounts that continue to provide benefits as appropriate to customers and the utilities in 2012 and 2013[130];
- Create new mechanisms to address uncontrollable or non-recurring matters appropriately;
- Discontinue the use of certain deferral accounts that are no longer required.

The Utilities have organized their deferral accounts into the six categories described in Table 6.3-1.

Table 6.3-1: Deferral Accounts Providing Benefits to Customers and the Utilities

Deferral Account Category	General Purpose & Description
Margin Related	• Decrease the volatility in rates caused both by such factors as fluctuations in gas prices and the significant impacts of weather and other changes on use rates. • Deferring the cost and delivery margin impacts arising from un-forecast variations in these types of factors and recovering the impacts from, or refunding the impacts to customers over a longer period of time is an effective method of reducing rate volatility.
Energy Policy	• Capturing costs associated with changing energy policies that focus on energy efficiency, conservation and the environment. • Deferring and amortizing these costs matches the costs of the programs with the period of time that the benefits are expected to be realized by customers.
Non-Controllable Items	• Items which are either outside of the Company's control or where the Company has limited ability to influence the costs. • Deferring the variances from the forecast level of costs for these activities reduces the exposure for both the Utility and customers due to significant variances in these amounts, and serves to avoid windfall gains or losses to the Company or to customers.
Deferred Costs of BCUC Applications	• Costs incurred consist of legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs.
Other	• Various accounts that provide benefits to customers and the Company, often for items that are non-recurring in nature.

[130] As per the Decision attached to Commission Order No. G-7-03 in referencing the approval of individual deferral accounts, the Commission wrote: "The Commission believes that its Orders supporting these requests continue in force until a change is approved by the Commission. For greater certainty, the Commission approves the continuation of amortization rates as previously ordered." Consistent with that Decision, the Utilities have continued to employ deferral accounts previously approved by the Commission.

Deferral Account Category	General Purpose & Description
Residual	• Deferral accounts which are no longer required and the Company is proposing to discontinue the use of the account. • Typically the proposal is to fully amortize any remaining balances.

The forecast mid-year balance of unamortized deferred charges in rate base for the FEUs is approximately $53.9 million in 2012 and $69.3 million in 2013 and is driven largely by the balances in the Whistler Pipeline and Energy Efficiency and Conservation accounts. Figure 6.3-1 provides the mid-year deferral account balances summarized by deferral account category.

Figure 6.3-1: FEU Forecast Mid-Year Balances of Deferral Accounts by Category

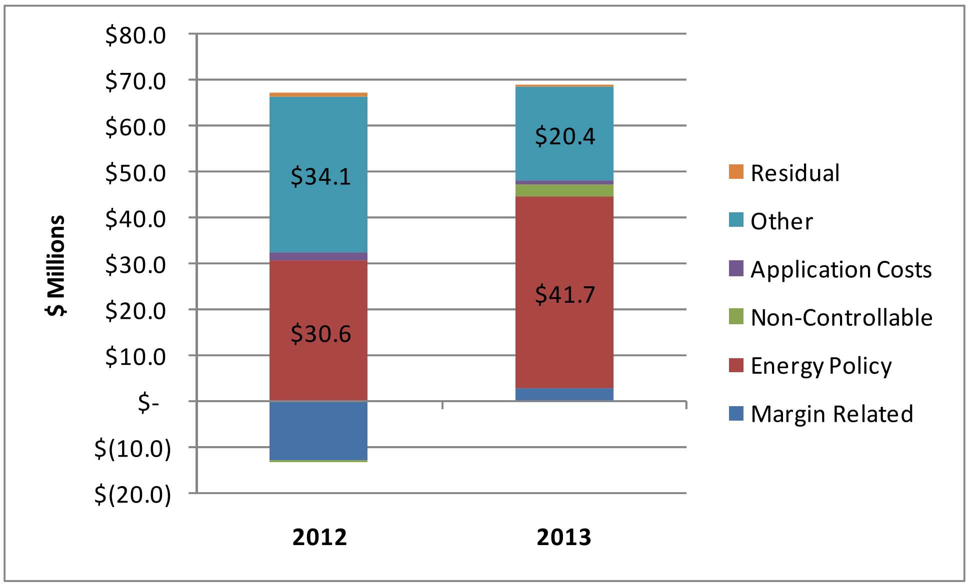


Table 6.3-2 provides the forecast mid-year balances of the deferral account by Category and by Utility and the following sections describe each rate base deferral account in detail, grouped by the six categories. For a discussion on non-rate base deferral accounts, including the Thermal Energy Services Deferral Account (formerly the New Energy Solutions Deferral Account), please refer to Appendix G.

Table 6.3-2: Forecast Mid-Year Balances of Deferral Accounts by Category[131]

2012 Forecast, Mid Year Balance, ($ thousands)					
	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ (9,371)	$ (4,062)	$ 703	$ (41)	$ (12,770)
Energy Policy	27,396	3,163	75	-	30,635
Non-Controllable	(614)	108	(79)	(4)	(589)
Application Costs	1,600	172	147	3	1,921
Other	7,686	(477)	26,761	96	34,065
Residual	711	-	(23)	-	688
Mid Year Balance, Deferral Accounts	**$ 27,407**	**$ (1,096)**	**$ 27,583**	**$ 54**	**$ 53,949**

2013 Forecast, Mid Year Balance, ($ thousands)					
	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ 2,529	$ -	$ 480	$ (7)	$ 3,003
Energy Policy	37,198	4,316	218	-	41,731
Non-Controllable	2,259	35	50	(2)	2,342
Application Costs	986	72	9	1	1,068
Other	(5,082)	(532)	25,947	91	20,423
Residual	684	-	-	-	684
Mid Year Balance, Deferral Accounts	**$ 38,574**	**$ 3,891**	**$ 26,703**	**$ 83**	**$ 69,252**

6.3.1 MARGIN RELATED DEFERRAL ACCOUNTS

The Utilities have included the following previously approved Margin Related Deferrals in rate base for 2012 and 2013:

131 Section 7.1 to 7.4, Schedules 66 to 71

Table 6.3-3: Margin Deferral Accounts Designed to Reduce Rate Volatility[132]

2012 Forecast, Mid Year Balance, ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account (CCRA)	$ (11,604)	$ -	$ (88)	$ -	$ (11,692)
Midstream Cost Reconciliation Account (MCRA)	15,506	-	99	-	15,604
Revenue Stabilization Adjustment Mechanism (RSAM)	(6,937)	-	703	(16)	(6,250)
Interest on CCRA/MCRA/RSAM/Gas in Storage	(1,507)	-	(11)	3	(1,515)
Revelstoke Propane Cost Deferral Account	94	-	-	-	94
Gas Cost Variance Account	-	(4,062)	-	-	(4,062)
Fort Nelson Gas Cost Reconciliation Account	-	-	-	(28)	(28)
SCP Mitigation Revenues Variance Account	(4,922)	-	-	-	(4,922)
Total Mid Year Balance, Margin Related Deferrals	**$ (9,371)**	**$ (4,062)**	**$ 703**	**$ (41)**	**$ (12,770)**

2013 Forecast, Mid Year Balance, ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account (CCRA)	$ -	$ -	$ -	$ -	$ -
Midstream Cost Reconciliation Account (MCRA)	9,303	-	59	-	9,363
Revenue Stabilization Adjustment Mechanism (RSAM)	(4,162)	-	422	(8)	(3,749)
Interest on CCRA/MCRA/RSAM	(22)	-	(1)	2	(21)
Revelstoke Propane Cost Deferral Account	-	-	-	-	-
Gas Cost Variance Account	-	-	-	-	-
Fort Nelson Gas Cost Reconciliation Account	-	-	-	-	-
SCP Mitigation Revenues Variance Account	(2,590)	-	-	-	(2,590)
Total Mid Year Balance, Margin Related Deferrals	**$ 2,529**	**$ -**	**$ 480**	**$ (7)**	**$ 3,003**

6.3.1.1 Commodity Cost Reconciliation Account (CCRA)

The CCRA applies to Mainland and Whistler and was approved by Commission Order No. G-25-04 for Mainland and Commission Order No. G-138-10 for Whistler. The CCRA captures the costs incurred by Mainland and Whistler to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity recovery revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. The commodity rate is reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Based on the recommendations within the FEI Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms (the "CCRA / MCRA Review Report"), dated March 10, 2011, a secondary parameter of a minimum rate change threshold value of $0.50/GJ would be added to the existing rate change trigger mechanism to avoid minor changes to the commodity rate which can occur in low commodity price environments when using only a percentage-based threshold. Generally, when the commodity rate is reset, the new rate is designed to recover, or refund, over the next 12 months any existing CCRA balance,

[132] Section 7.1 to 7.4, Schedule 68 and 70

along with any under or over recovery of commodity costs forecast to occur over the next 12-month period. Consistent with past practice, any variances that arise in 2012 and 2013 between the forecast CCRA balances and the actual amounts realized will be subject to deferred interest treatment

6.3.1.2 Midstream Cost Reconciliation Account (MCRA)

The MCRA captures the costs the Mainland and Whistler incur in performing the midstream function and the revenues collected through midstream rates. Gas Supply, in its midstream role, uses the pipeline and storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plans to manage load variability. The MCRA accumulates any resultant cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream rates. Midstream rates are reviewed on a quarterly basis and, under normal circumstances, midstream rates are adjusted on an annual basis with a January 1 effective date. Based on the recommendations within the CCRA / MCRA Review Report, when midstream rates are reset for the upcoming calendar year, the new rates will be designed to amortize 1/3 of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates; effectively lengthening the amortization period related to the yearend MCRA balance to help reduce year-to-year rate volatility. Consistent with past practice, any variances that arise in 2012 and 2013 between the forecast MCRA balances and the actual amounts realized will be subject to deferred interest treatment.

6.3.1.3 Revenue Stabilization Adjustment Mechanism (RSAM)

The RSAM, originally approved by Commission Order No. G-59-94, and subsequently approved for Fort Nelson through Commission Order No. G-17-04 and Whistler through Commission Order No. G-138-10, is a mechanism that stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes in Mainland and all customers in Whistler and Fort Nelson. The RSAM enables the Companies to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use. If actual use is less than forecast, the RSAM deferral account is charged for the variance in use times the delivery rate and the RSAM revenue is credited. Conversely, if actual use is greater than forecast, the RSAM deferral account is credited and the RSAM revenue is decreased. Consistent with past practice, any variances that arise in 2012 and 2013 between the forecast RSAM balances and the actual amounts realized will be subject to deferred interest treatment.

The 2012 account balance variances and the associated deferred interest will be returned to or recovered from customers through an adjustment to Rate Rider 5 from 2013 to 2015; the 2013 account balance variances and the associated deferred interest will be returned to or recovered from customers through an adjustment to Rate Rider 5 from 2014 to 2016.

MAINLAND

RSAM account balances will continue to be recovered from or returned to customers (Rates 1, 1B, 1U, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23) through Delivery Rate Rider 5 over a three year period. The determination of Mainland Delivery Rate Rider 5 is discussed in Section 3.3.1, and Section 7.1, Schedule 85.

WHISTLER

In this Application, Whistler is seeking approval to transfer the residual balance in the Whistler Sales Margin Differential account to the RSAM account effective January 1, 2012, as the balances in both of these accounts arise primarily from changes in use rates as compared to forecast. As approved by Commission Order No. G-138-10, Whistler discontinued the use of the Sales Margin Differential account upon the adoption of the RSAM in 2010. In addition, Whistler is seeking approval to recover from or return to all customers the combined RSAM account balances through a Delivery Rate Rider, amortized over a three year period. Consistent with the Mainland and Fort Nelson, Whistler will use the same Delivery Rate Rider 5. The determination of Whistler Delivery Rate Rider 5 is discussed in Section 3.3.3 and Section 7.3, Schedule 85.

FORT NELSON

RSAM account balances will continue to be recovered from or returned to all customers through Delivery Rate Rider 5 over a three year period.[133] The determination of Fort Nelson Delivery Rate Rider 5 is discussed in Section 3.3.4 and Section 7.4, Schedule 85.

6.3.1.4 Interest on CCRA, MCRA, RSAM and Gas in Storage

Consistent with past practice, and as approved by Commission Order No. G-7-03, variances from the forecast CCRA, MCRA, and RSAM balances attract interest at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers. Balances in these accounts and variances from the forecast amounts will be recovered from or returned to customers using the same methodology as outlined above for the associated CCRA, MCRA and RSAM accounts.

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[133] RSAM recovery or refund is embedded within the bundled step rates for those customers that do not have an unbundled gas cost recovery rate

Pursuant to Commission Order No. G-141-09, Mainland received approval for deferred interest treatment on variations between the forecast balance of gas in storage inventory included in rate base, and the actual balance in the account through the year. In this Application, Mainland is seeking approval for an amortization period of three years for the Gas in Storage Interest account.

6.3.1.5 Revelstoke Propane Cost Deferral Account

The Revelstoke Propane Cost Deferral Account, approved by BCUC Order No. G-72-90, captures the difference between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane. The propane reference price is reviewed on a quarterly basis, and typically reset when the propane recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. It is expected the secondary parameter of a minimum commodity rate change threshold value of $0.50/GJ, as recommended in the CCRA / MCRA Review Report, would apply to other gas utilities regulated by the Commission and would therefore be applicable to Revelstoke. In general, when the propane reference price is reset, the new reference price is designed to recover, or refund, over the next 12 months any existing deferral account balance, along with any under or over recovery of propane costs forecast to occur over the next 12-month period.

6.3.1.6 Gas Cost Variance Account (GCVA)

Approved by Commission Order No. G-2-03, the Vancouver Island GCVA was established effective January 1, 2003 to accumulate the variances between the actual and the forecast gas costs on a royalty adjusted basis, for amortization and recovery from, or refund to, sales customers in future rates. The Royalty Rebate arrangement under which Vancouver Island has received royalty revenues from the Province expires on December 31, 2011; the GCVA will continue to collect the variances between the actual and forecast gas costs during 2012 and 2013.

Although the Vancouver Island forecast gas costs and GCVA balances have continued to be reported on a quarterly basis, the Vancouver Island sales rates were not subject to resetting for flow through of gas costs during the 2010-2011 revenue requirements settlement period. The GCVA is projected to have a surplus balance at December 31, 2011 of approximately $11.1 million ($8.1 million after tax), which will be amortized in 2012.

For purposes of this Application, the GCVA balances at the end of 2012 and 2013 are forecast to be zero; however, differences between the actual and forecast gas costs will occur. Vancouver Island proposes that these variances continue to be accumulated in the GCVA for the two-year period, and that the December 31, 2013 balance be amortized through future rates. Further, as the Vancouver Island 2012 and 2013 sales rates sought within this Application will not be subject to resetting for flow through of gas costs during the 2012-2013 revenue requirements period, FEVI is proposing to discontinue the quarterly reporting of the Vancouver Island forecast gas costs and GCVA balances.

6.3.1.7 Fort Nelson Gas Cost Reconciliation Account (GCRA)

The GCRA accumulates the actual costs incurred by Fort Nelson to purchase gas, and the amounts recovered through the gas cost component of rates. The Fort Nelson gas cost recovery rates are reviewed on a quarterly basis, and typically reset when the gas cost recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. It is expected the use of a secondary parameter of a minimum commodity rate change threshold value of $0.50/GJ, as recommended in the CCRA / MCRA Review Report, would apply to Fort Nelson, as well as other gas utilities regulated by the Commission. Generally, when Fort Nelson gas cost recovery rates are reset, the new rates are designed to recover, or refund, over the next 12 months any existing GCRA balance, along with any under or over recovery of gas costs forecast to occur over the next 12-month period.

6.3.1.8 SCP Mitigation Revenues Variance Account

The SCP Mitigation Revenues Variance Account, approved by Commission Orders No. G-124-00, No. G-123-01, No. G-7-03 and No. G-141-09, relates to the use of SCP transportation capacity that has not been utilized by the firm transportation agreement customers and is sold to others, and the third party back-haul movements from Kingsvale to Yahk which relate to transportation service in a West to East direction through the system. As discussed in Section 5.5, Other Revenue, FEI has increased the forecast SCP mitigation revenues for 2012 and 2013 to $5.7 million as a result of the T-South Enhanced Service initiative between Spectra Energy and FEI. Any variation from this $5.7 million and actual revenues received will be captured in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a three year period through delivery rates.

6.3.2 ENERGY POLICY DEFERRAL ACCOUNTS

The Utilities have included the following previously approved, modified and new deferrals related to changing energy policy in rate base for 2012 and 2013:

Table 6.3-4: Mid-Year Balances of Energy Policy Deferrals[134]

2012 Forecast, Mid Year Balance, ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC)	$ 26,571	$ 3,147	$ 75	$ -	$ 29,793
NGV Conversion Grants	101	17	-	-	118
Emissions Regulations	-	-	-	-	-
2010-2011 Biomethane Program Costs	748	-	-	-	748
2011 CNG and LNG Service Costs and Recoveries	(24)	-	-	-	(24)
CNG and LNG Service Recoveries	-	-	-	-	-
Total Mid Year Balance, Energy Policy Deferrals	**$ 27,396**	**$ 3,163**	**$ 75**	**$ -**	**$ 30,635**

2013 Forecast, Mid Year Balance, ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC)	$ 36,665	$ 4,290	$ 218	$ -	$ 41,173
NGV Conversion Grants	119	26	-	-	145
Emissions Regulations	-	-	-	-	-
2010-2011 Biomethane Program Costs	449	-	-	-	449
2011 CNG and LNG Service Costs and Recoveries	(36)	-	-	-	(36)
CNG and LNG Service Recoveries	-	-	-	-	-
Total Mid Year Balance, Energy Policy Deferrals	**$ 37,198**	**$ 4,316**	**$ 218**	**$ -**	**$ 41,731**

6.3.2.1 Energy Efficiency and Conservation (EEC)

Pursuant to Commission Order No. G-36-09, the Commission approved the use of a deferral account for EEC expenditures for Mainland and Vancouver Island. The decision also approved the inclusion of the forecast deferral account balances in rate base on a net-of-tax basis and to amortize these balances in rates over a ten year period. The Companies propose that the deferral account mechanism be modified to address variances in the level of customer participation as well as to address the expansion of the EEC program to Whistler.

In this Application the Companies are seeking the following approvals related to EEC:

1. An increase of $35.3 million to the approved EEC funding envelope in 2011 to a total of $74.5 million in 2012 and remaining at that level in 2013 for Mainland, Vancouver Island and Whistler combined;
2. Combined EEC rate base deferral account additions of $20.0 million in 2012 and $20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period;
3. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is

[134] Section 7.1 to 7.4, Schedule 68 and 70

approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler;

4. The creation of the EEC Incentive non-rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.

All costs incurred by the Companies continue to be subject to the guidelines of the EEC Application, as approved by Commission Order No. G-36-09. The four requests are discussed in further detail below.

INCREASE TO EEC FUNDING

In this Application, the Companies are seeking approval of an increase to the EEC funding envelope from the 2011 approved amount of $35.3 million to $74.5 million for 2012 and 2013.

Table 6.3-5 below summarizes the various areas of activity to be funded by the proposed EEC expenditure.

Table 6.3-5: Proposed EEC Funding by Activity for 2012 and 2013

	2012 Proposed Funding ($000's)	2013 Proposed Funding ($000's)
	Total	**Total**
Previously Approved EEC Activity		
Conventional EEC Activity		
Residential	9,500	9,500
High Carbon Fuel Switching	2,000	2,000
Low Income	5,000	5,000
Commercial	14,500	14,500
Conservation Education and Outreach	5,000	5,000
Industrial	2,000	2,000
Subtotal - Conventional EEC Activity	***38,000***	***38,000***
Subtotal - Innovative Technologies inc. NGT	***11,500***	***11,500***
Subtotal - Previously Approved EEC Activity	***49,500***	***49,500***
New Initiatives		
Furnace Scrap-It program	**10,000**	**10,000**
Solar Thermal	**4,000**	**4,000**
TES for Schools	**11,000**	**11,000**
Subtotal - New Initiatives	***25,000***	***25,000***
Total Funding	**74,500**	**74,500**

This level of funding is necessary to build on the significant progress that has been made toward building a strong foundation for future growth in EEC activity, to support new EEC programs and to make EEC programs available to customers in Whistler[135] in addition to customers on the Mainland and Vancouver Island and to include Industrial customers of FEVI in eligibility for EEC program participation. Further, in this RRA, the Utilities have requested $10 million in 2012 and $10 million in 2013 to fund its natural gas for Transportation initiatives within the Innovative Technologies Program Area. Further, the FEU have put forth new programs such as Furnace Scrap-It program, Solar Thermal and TES for Schools. Appendix K provides a review of the proposed EEC activity for 2012 and 2013, and the EEC-related approvals sought along with supporting information.

The table below provides a summary of the 2010 through 2013 EEC activity:

Table 6.3-6: A Significant Increase in EEC Funding is Proposed

($ millions)	2010		2011		2012	2013
Utility/Region	*Approved*	*Actual*	*Approved*	*Projected*	*Forecast*	*Forecast*
FEI	25.8	11.1	29.6	20.0	74.5	74.5
FEVI	5.2	1.5	5.7	5.7		
FEW	-	-	-	-		
Total	**31.0**	**12.6**	**35.3**	**25.7**	**74.5**	**74.5**

EEC FORECAST INCLUDED IN RATE BASE

The Companies are seeking approval to include $20 million per year in the EEC rate base deferral account, slightly less than 30 percent of the total forecast, to recognize the variability in customer participation that may occur in the forecast period. As discussed below, the remaining $54.5 million per year of the forecast EEC costs will be accumulated, on an actual as-spent basis, in a non-rate base deferral account, attracting AFUDC. This approach helps to protect customers from paying for EEC expenditures in 2012 and 2013 until program results are known.

The Companies believe that $20 million per year is an appropriate forecast to include in the rate base deferral account for 2012 and 2013 because of the following:

1. $20 million is in line with the total projected EEC costs for 2011.
2. As demonstrated in the 2010 EEC Annual Report, FEI's recent experience of the ratio between non-incentive costs to incentive costs is approximately 35 percent.[136]

[135] In Appendix A (page 7), Reasons for Decision accompanying Commission Order No. G-138-10, Whistler was directed to develop plans for EEC programs consistent with British Columbia's energy objectives in its next revenue requirement application

[136] Appendix K; Non incentive costs of $6.283 million compared to total costs of $17.701 million as shown on Page 6

3. $20 million reflects the approximate level of non-incentive costs like labour, customer education and general administrative expenses required to deliver an EEC program of $74.5 million.

ALLOCATION OF EEC FORECAST IN RATE BASE

The Companies are seeking approval to allocate the forecast costs included in the rate base deferral account on an average customer basis amongst Mainland, Vancouver Island and Whistler. This results in rate base deferral account additions as follows:

Table 6.3-7: EEC Additions Allocated Based on Average Customers

($ millions) **Utility/Region**	**EEC Rate Base Additions**		
	Allocation	**2012**	**2013**
FEI	89%	17.8	17.8
FEVI	10%	2.0	2.0
FEW	1%	0.2	0.2
Total	100%	20.0	20.0

The allocation of the forecast costs in rate base on an average customer basis is appropriate because the programs will be available to customers in all regions.

EEC INCENTIVE NON-RATE BASE DEFERRAL ACCOUNT

The Companies are seeking approval of a non-rate base deferral account, attracting AFUDC, to capture the remaining portion of EEC costs as incurred on an actual basis, to a maximum of $54.5 million each year amongst the Companies. The non-rate base account reduces the risk of variability in EEC costs of customer participation in program costs that are embedded in delivery rates. That is, costs incurred over and above the forecast EEC rate base account additions of $20.0 million in 2012 and 2013 will be captured in the EEC Incentive non-rate base account. The additions to the non-rate base account will be tracked on a Company basis for Mainland, Vancouver Island and Whistler.

Consistent with the rate base deferral accounts, the balance in the non-rate base account will be recovered over a ten year period. The recovery of the balance will commence in 2014, with the method of recovery to be determined as a part of the next Revenue Requirement.

6.3.2.2 NGV Conversion Grants

Mainland and Vancouver Island maintain a NGV Conversion Grant Program, as approved by Commission Order No. G-98-99 for FEI and Commission Order No. G-140-09 for FEVI. The NGV Conversion Grant program is not a part of the EEC Program maintained by FEI and FEVI.

The Companies record the actual amount of grants in the NGV Conversion Grants deferral account, and amortize them in rates over five years. Any variances between the forecast level of expenditures and actual expenditure levels will be amortized in rates beginning in 2014.

6.3.2.3 Compliance with Emissions Regulations

The growing number of regulations around emissions trading may result in incremental compliance costs and recoveries during the forecast period. These compliance costs and recoveries are difficult to forecast because of uncertainty around the final form and applicability of emissions trading regulations. Currently, the Emissions Trading Regulation and the Renewable and Low Carbon Fuel Requirements Regulation ("RLCFRR") are two regulatory mechanisms aimed to reduce GHG emissions in BC. These two regulations, as discussed further below, impact us in two ways: 1) we are required to reduce our own operating emissions, and 2) we can sell our credits from renewable energy to other firms or use them to offset excess emissions in other parts of our operations. However, given the uncertainty with these regulations at this point, the Utilities request approval for the rate base Compliance to Emissions Regulations Deferral Account to capture potential compliance costs and revenues collected from credits.

The Emissions Trading Regulation ("Cap and Trade" regulation), currently in the process of being discussed with partners in the Western Climate Initiative, is proposed to start in 2012, but is yet to be legislated. The past year has raised doubts in terms of global negotiations over climate change and carbon markets, including emission trading schemes. The U.S. has failed to move forward its plans for cap and trade at the federal level for the foreseeable future. California is planning to launch its own state program in 2012 and other Canadian and U.S. jurisdictions were planning to follow. However, a recent California judge ruled that California did not adequately consider alternatives to its plan to create a cap-and-trade market for carbon emissions, a setback for the most aggressive effort by a state to combat climate change. This ruling placed California's global warming and climate change program on hold and brings into question whether the California cap-and-trade system will start on time in January 2012. Furthermore, our Province's approach to emissions trading is still questionable, especially given the recent changes in our political landscape. BC has reportedly stated that, although the legislative framework is in place to be ready for 2012 implementation of cap and trade, the timing remains subject to provincial government decision. BC's new Environment Minister, Terry Lake, recently announced that Premier Christy Clark needs to re-evaluate the cap-and-trade proposal to ensure it wouldn't undermine the province's competitiveness.

The cap-and-trade regulations may apply to the Utilities' operating emissions, requiring the Utilities to comply with the requirements. There are financial impacts associated with complying with cap-and-trade regulation, including purchasing allowances and offsets, or making internal reductions to meet targets. The Utilities have processes and controls in place for capturing, measuring, and reporting GHG emissions and have worked towards a carbon management strategy, including steps to reduce operating emissions, which will help achieve compliance with the potential cap-and-trade regulation. However, there is uncertainty regarding the final form of the cap-and-trade regulation that is well suited to a deferral account mechanism. Some of the key concerns and uncertainties associated with cap and trade are as follows:

- Baseline and emissions targets;
- Treatments of fugitives and vented emissions (including third party damages);
- Approach to distribution of allowances;
- Limitation on use of offsets – potential that no more than 49 percent of emission reductions may come from offsets; and
- Carbon price - potential of $30 per tonne.

The Province of BC has also legislated the RLCFRR, which addresses the transportation sector's contribution to GHG emissions in BC. Starting in 2011, Part 3 fuel suppliers will have to meet annual targets, or pay a penalty. Natural gas, propane, electricity and hydrogen are Part 3 fuels if they are sold for use in transportation. *"A Part 2 or Part 3 fuel supplier who manufactures fuel in British Columbia for the first time or imports fuel into British Columbia for the first time, or uses it for the first time, is responsible for compliance unless there is a written agreement stating otherwise."*

Since we sell natural gas for transportation under various rate classes, we have the opportunity to claim first sale as a 'Part 3' fuel supplier in the Province. This regulation allows for emissions credits and obligations based on required carbon intensity baseline. Those suppliers who are not in compliance with the mandated reductions in carbon will have to purchase credits from others or pay a penalty of $200/tonne for deficiencies. As we add more CNG and LNG sales, our credits will continue to increase as it is measured against the conventional fuel intensity baseline, which creates a potential revenue stream for us, benefiting our customers.

As a result of the above-mentioned concerns and uncertainties, it is difficult to forecast associated costs and revenues with cap and trade and RLCFRR regulations, and we request a deferral account to capture both compliance costs, and revenues collected associated with these regulations. For purposes of the 2012 and 2013 revenue requirement, additions to this account have not been forecast and the amortization of any balance that accumulates in this account will be addressed in a future revenue requirement application.

6.3.2.4 2010-2011 Biomethane Program Costs

In accordance with Commission Order No. G-194-10, FEI has created a non-rate base deferral account attracting AFUDC to capture the biomethane costs applicable to all customers incurred prior to January 1, 2012. Commencing January 1, 2012, this account is transferred to rate base and is amortized through delivery rates over a three year period. The 2010 and 2011 costs captured in the deferral account include:

1. The 2010 and 2011 cost of service value related to the assets that are being transferred to Rate Base in 2012 – i.e. Earned Return, Depreciation Provision, and Income Tax; and
2. O&M expenditures (net of tax), consisting of the costs of upgrading the CWLP system to allow the launch of the Green Gas program and the ongoing costs of updating that tariff information, the costs of CWLP answering informational calls regarding the Green Gas program and other planned Customer Education costs and the cost of one FTE to administer the Green Gas program. Additionally, FEI has included the BCUC application costs incurred in support of the Biomethane Application filed on June 8, 2010.

Any variances between the forecast level of 2011 expenditures and actual expenditure levels will be amortized in rates beginning in 2014. Delivery system-related Capital and O&M costs incurred after December 31, 2011 have been forecast as part of this Application and will not be included in this deferral account.

Please refer to Appendix J for a comprehensive report on the biomethane program and details regarding the balance of all deferral accounts associated with biomethane.

6.3.2.5 2011 CNG and LNG Service Costs and Recoveries

In the recent CNG and LNG Service Application, FEI requested approval for a non-rate base deferral account attracting AFUDC to capture the O&M costs and cost of service associated with the capital additions to the delivery system incurred and the CNG and LNG Service recoveries received prior to January 1, 2012, and to recover or refund the balance to all non-bypass customers by amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. FEI has captured the forecast costs and revenues associated with the Waste Management Fueling Station agreement, as well as two additional fueling station agreements which are anticipated to be in-service in 2011, in this non-rate base deferral account, and has transferred the projected balance to rate base January 1, 2012 with three year amortization. Any variances between the forecast level of 2011 expenditures and revenues and actual expenditure and revenue levels will be amortized in rates beginning in 2014. CNG and LNG Service costs and recoveries incurred after December 31, 2011 are embedded in this Application and used in the determination of the revenue requirements for 2012 and 2013.

The forecasts made in relation NGV refuelling infrastructure in the 2012-2013 RRA are premised on the assumption that the CNG and LNG Service Application will be approved as filed. Further, it is also based on the premise that the EEC incentives for natural gas for Transportation will continue. If necessary, FEI will file an evidentiary update to this application to take into account the Commission's Decision on the CNG and LNG Service Application once it is available.

Please refer to Appendix I for a comprehensive report on the CNG and LNG Fueling Program and details regarding the balance of all deferral accounts associated with the program.

6.3.2.6 CNG and LNG Service Costs and Recoveries

In its recent CNG and LNG Service Application dated December 1, 2010, FEI requested approval for an ongoing rate base deferral account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. In this Application, FEI is seeking approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16 of $2.9 million in 2012 and $4.4 million in 2013. FEI believes that a deferral account is appropriate because Rate Schedule 16 is a relatively new rate schedule and at the time of this filing we have no customers using this service. It is expected that Vedder Transportation will be the first customers to use this Rate Schedule beginning in the second half of 2011. While FEI believes its CNG and LNG forecasts to be reasonable, FEI believes that both the customer and the shareholder should be kept whole with respect to Rate Schedule 16 and fuelling station recoveries for CNG and LNG Service and that a deferral account mechanism is appropriate, at least for the 2012 and 2013 forecast period.

Additions to this account over the forecast period will be recovered from or refunded to all non-bypass customers beginning in 2014. Please refer to Appendix I for a comprehensive report on the CNG and LNG Fueling Program.

6.3.3 NON-CONTROLLABLE DEFERRAL ACCOUNT ITEMS

The Utilities have included the following previously approved and new Non-Controllable Items deferrals in rate base for 2012 and 2013 as shown in Table 6.3-8. As discussed in Section 3, Vancouver Island is seeking approval for the continuation of the RSDA for the 2012 and 2013 forecast period. In the absence of the RSDA, Vancouver Island would seek approval of Non-Controllable Item deferral accounts similar to those employed in Mainland, Whistler and Fort Nelson.

Table 6.3-8: Non-Controllable Item Deferral Accounts[137]

2012 Forecast, Mid Year Balance, ($ thousands)					
Non-Controllable Items Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Property Tax Deferral	$ (1,339)	$ -	$ 80	$ (2)	$ (1,262)
Insurance Variance	(598)	-	-	-	(598)
Pension & OPEB Variance	7,978	-	-	-	7,978
BCUC Levies Variance	118	-	-	-	118
Interest Variance	(3,928)	-	(165)	(2)	(4,094)
Tax Variance Account	(3,513)	-	(1)	-	(3,514)
Vancouver Island HST Implementation	-	(66)	-	-	(66)
Olympic Security Costs	285	67	2	-	353
IFRS Conversion Costs	384	39	5	-	428
Customer Service Variance Account	-	-	-	-	-
Vancouver Island Joint Venture Litigation Costs	-	68	-	-	68
Total Mid Year Balance, Non-Controllable Items Deferrals	**$ (614)**	**$ 108**	**$ (79)**	**$ (4)**	**$ (589)**

2013 Forecast, Mid Year Balance, ($ thousands)					
Non-Controllable Items Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Property Tax Deferral	$ (593)	$ -	$ 50	$ (1)	$ (543)
Insurance Variance	-	-	-	-	-
Pension & OPEB Variance	4,787	-	-	-	4,787
BCUC Levies Variance	-	-	-	-	-
Interest Variance	(2,157)	-	-	(1)	(2,158)
Tax Variance Account	-	-	-	-	-
Vancouver Island HST Implementation	-	-	-	-	-
Olympic Security Costs	94	22	(2)	-	114
IFRS Conversion Costs	128	13	2	-	143
Customer Service Variance Account	-	-	-	-	-
Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-
Total Mid Year Balance, Non-Controllable Items Deferrals	**$ 2,259**	**$ 35**	**$ 50**	**$ (2)**	**$ 2,342**

6.3.3.1 Property Tax Deferral

The Company has limited ability to influence property taxes, which are imposed by municipalities and other levels of government, and are influenced by assessed property values, mill rates, and shortfalls in other areas within a municipal boundary. A significant portion of property taxes is tied to the amount of revenues collected within municipalities ("1 percent in lieu" tax), and fluctuates with commodity-related variations in revenues. Mainland, Whistler and Fort Nelson will continue to defer the variance between actual and forecast property taxes, as most recently approved by Commission Order No. G–51-03 for FEI, Commission Order No. G-35-09 for Whistler and Commission Order No. G-27-11 for Fort Nelson. Any variances in amounts forecast will be amortized in rates starting in 2014.

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[137] Section 7.1 to 7.4, Schedule 68 and 70

With this Application, Whistler is requesting to include the balance of its existing Propane Plant Property Tax Deferral account (forecast December 31, 2011 balance of $101 thousand) into its Property Tax Deferral account. Also, for consistency with the approved amortization period for the Mainland, both Whistler and Fort Nelson request approval to amortize their deferral account balances in rates over a three year period, rather than the currently approved amortization period of one year.

6.3.3.2 Insurance Variance

Insurance costs may differ significantly from the levels forecast, due to changes in economic factors and natural disasters outside of the control of the Companies. The impact of these types of events cannot be incorporated in insurance premium forecasts. A deferral account for these variances with amortization over a one year period was approved by Commission Order No. G-51-03 for Mainland and Commission Order No. G-2-03 for Vancouver Island. The Companies have continued with this account and treatment. Any variances from amounts forecast will be amortized in rates in 2014.

6.3.3.3 Pension and OPEB Variance

A deferral account for pension and OPEB variances was approved by Commission Order No. G-51-03 and No. G-141-09 for Mainland and Commission Order No. G-2-03 for Vancouver Island. Volatility in the accounting expense related to both pension and OPEB costs is likely to continue. It is therefore critical that variations from forecast are captured in a deferral account, both to avoid large fluctuations in recovered amounts from year to year, and to allow for the uncontrollable nature of these costs. The Utilities will continue this deferral account treatment for pensions and OPEB costs, with amortization over a three year period. Any variances from amounts forecast will be amortized in rates starting in 2014.

The significant additions to this account in 2011 are due to the deferral of the adoption date to IFRS. At the time that delivery rates were approved for 2011, the IFRS adoption date was January 1, 2011, and therefore pension and OPEB expenses were forecast under IFRS for 2011. With the adoption date deferred to January 1, 2012, the Companies continued to record their pension and OPEB expense in 2011 under Canadian GAAP. As a result, the difference between the approved IFRS expense and the actual Canadian GAAP expense for 2011 was captured in the Pension and OPEB Variance account.

6.3.3.4 BCUC Levies Variance

Variations in BCUC levies from those recovered in rates were approved for deferral account treatment by Commission Order No. G-112-04 for Mainland and Commission Order No. G-140-09 for Vancouver Island, with amortization in the following year. The account recognizes that the amount of funding that the Commission requires is dependent on a number of factors that are outside the control of the Utilities. Any variances from amounts forecast will be amortized in rates in 2014.

6.3.3.5 Interest Variance

The Interest Variance deferral account allows the Mainland, Whistler and Fort Nelson to avoid potential gains or losses on forecasting of interest rates. This account captures the impact on interest expense of interest rates variances and variances in the timing of long-term debt issues, as compared to forecast. In Fort Nelson, this account captures the Fort Nelson portion of the Mainland deferred interest account. This deferral was previously approved by Commission Order No. G-7-03 for Mainland with amortization in rates over three years and by Commission Order No. G-35-09 for Whistler and Commission Order No. G-147-09 for Fort Nelson, with amortization over one year in both utilities.

In this Application, Whistler and Fort Nelson are seeking approval to change the amortization period from one year to three years for consistency with Mainland. Any variances from amounts forecast will be accumulated and amortized in rates starting in 2014.

6.3.3.6 Tax Variance Account

At any time, the Companies can face changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed. As such, Mainland and Whistler will continue to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction. This deferral was previously approved by Commission Order No. G-141-09 for Mainland, with amortization over one year. In Whistler, this account was approved by Commission Order No. G-138-10; however, an amortization period was not determined. Whistler believes that an amortization period consistent with Mainland is appropriate for this account and is seeking approval in this Application for amortization over a one year period.

For purposes of the 2012 and 2013 revenue requirement, additions to this account have not been forecast and any variances will be accumulated and amortized in rates starting in 2014. Additions to the Tax Variance Account in 2010 and 2011 were as a result of a change in the tax treatment of removal costs, the impact of the transition to HST and costs incurred in Mainland associated with the LILO reassessment. These additions are described further below.

2010 AND 2011 REMOVAL COST BENEFITS

As discussed in Section 5.6.6.2, during 2010, the Companies determined that it is reasonable to deduct removal costs in the year incurred for income tax purposes. Mainland and Whistler have deferred the tax benefits, as shown in Table 6.3-8, relating to the 2010 tax deduction and will do the same for 2011. The analysis to support the deduction of these benefits was not completed in time to include them in rates for 2010 and 2011. The Vancouver Island removal cost benefits in 2010 and 2011 are captured in the Vancouver Island RSDA.

Table 6.3-9: Removal Cost Tax Benefits Returned Through the Tax Variance Account and RSDA

($ thousands) **Utility/Region**	**Actual 2010**	**Forecast 2011**
Mainland	$ 2,291	$ 2,992
Vancouver Island	98	98
Whistler	1	1
Total	**$ 2,390**	**$ 3,091**

2010 AND 2011 HST TRANSITION IMPACT

In an Application filed with the BCUC on September 27, 2010, the FEU proposed that the 2010 and 2011 revenue requirement impacts of the implementation of HST be recorded in the applicable Tax Variance Deferral Accounts and returned to customers as part of the 2012 Revenue Requirements filings. The addition to the Mainland deferral account over the two year period is a net benefit to customers of $1.3 million (net of tax). The net impact to Whistler is nil because the benefit of the Social Services Tax savings of $2 thousand is fully offset by HST implementation costs of $2 thousand.

MAINLAND LILO REASSESSMENT

FEI received approval through Commission Order No. G-141-09 for a non-rate base deferral account to record potential payments to CRA and legal costs associated with a LILO agreement tax reassessment. This matter was successfully resolved in favour of customers in early 2011 and as a result, FEI incurred legal costs of $52 thousand in 2010. Due to the nature of the costs and their size, FEI is seeking approval to discontinue the LILO Reassessment non-rate base account and to include the LILO reassessment costs in the Tax Variance Account instead.

6.3.3.7 Vancouver Island HST Implementation

In accordance with the proposed treatment of the impact of the HST transition and as indicated in the letter filed with the Commission on September 27, 2010, Vancouver Island has captured the revenue requirement impact of the HST transition in 2010 and 2011, net of implementation costs in an HST Implementation deferral account. The December 31, 2011 closing balance in this account is $133 thousand, net of tax. In this Application, Vancouver Island is seeking approval for this account and to refund the forecast December 31, 2011 closing balance to customers in rates over a one year period.

6.3.3.8 Olympic Security Costs

The security costs related to the 2010 Olympic and Paralympic games, approved for deferral treatment by Commission Order No. G-191-08, with an allocation to Vancouver Island and

Whistler based on average customers, have been amortized over three years commencing in 2011. This account is forecast to be fully amortized by December 31, 2013.

6.3.3.9 IFRS Implementation Costs

The costs associated with the conversion to IFRS, approved for deferral treatment by Commission Order No. G-191-08, with an allocation to Vancouver Island and Whistler based on average customers, have been amortized over three years commencing in 2011. The account is expected to be fully amortized by December 31, 2013. The FEU believe that these costs should be recovered from customers as previously approved, despite the planned adoption of US GAAP by the Utilities. While these costs were incurred as part of the planned transition to IFRS, there has been a great deal of value obtained from the knowledge gained and the system changes implemented as a result that will continue to provide value despite the fact that IFRS conversion will not be completed. Some of the costs incurred to date have resulted from the FEU involvement in industry initiatives aimed at achieving IFRS changes that would have allowed for the recognition of regulated assets and liabilities, and in doing so would have eliminated the current necessity to adopt US GAAP as opposed to IFRS. The costs already incurred for IFRS have also assisted in establishing fact patterns and identifying accounting differences, and may be used to address future accounting changes. Many of these costs also support the adoption of US GAAP and any convergence that will likely continue to occur between US GAAP and IFRS.

6.3.3.10 Customer Service Variance Account

In 2012 and 2013, the Customer Service department will be faced with business uncertainties as discussed in detail in Section 5.3.7 and the Companies are requesting a deferral account to capture actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for the ongoing operating costs of the in-sourced activities, as outlined in Table 5.3-32. The types of uncertainties that the deferral account will address include fluctuations in call volumes, the rate of customer adoption of new communication channels and self serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, and any variances in the anticipated duration required for new staff to become skilled and proficient at their responsibilities.

The variance account will also capture spending variances in meter reading costs primarily due to the timing of BC Hydro's Smart Metering Initiative and its impact on joint gas/electric meter reads in 2012 and the uncertainty of costs in 2013, as an outsourced provider has yet to be confirmed since BCH will not require large scale manual meter reading service at that time. For purposes of the 2012 and 2013 revenue requirement, additions to this account have not been forecast and the disposition of any balance that accumulates in this account will be addressed in a future revenue requirement application.

6.3.3.11 Vancouver Island Joint Venture Litigation Costs Account

In this Application, Vancouver Island is seeking approval for a deferral account to capture the legal costs of $130 thousand incurred defending a lawsuit filed by the Vancouver Island Gas Joint Venture (VIGJV). This lawsuit was dismissed in January 2010. The basis of this lawsuit was alleged overpayment of past tolls and declarations for reduction of future tolls. Had the VIJV been successful in their claim, it would have likely resulted in additional costs and a reallocation of cost of service for all other customers. Vancouver Island is seeking approval to amortize this account through delivery rates in 2012.

6.3.4 DEFERRED COSTS OF APPLICATIONS

The Utilities have included the following previously approved and new deferrals related to costs of filing regulatory applications in rate base for 2012 and 2013:

Table 6.3-10: Approved and Forecast Application Cost Accounts[138]

2012 Forecast, Mid Year Balance, ($ thousands)					
Application Costs Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$ 582	$ 34	$ 4	$ -	$ 621
2010-2011 Revenue Requirement Application	(82)	-	132	-	50
2012-2013 Revenue Requirement Application	654	70	7	3	734
CCE CPCN Application	178	17	2	-	197
NGV for Transportation Application	123	-	-	-	123
Victoria Regional Office CPCN	-	35	-	-	35
Long Term Resource Plan Application	144	16	2	-	162
Total Mid Year Balance, Application Costs Deferrals	**$ 1,600**	**$ 172**	**$ 147**	**$ 3**	**$ 1,921**

2013 Forecast, Mid Year Balance, ($ thousands)					
Application Costs Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$ 414	$ 20	$ 3	$ -	$ 437
2010-2011 Revenue Requirement Application	-	-	-	-	-
2012-2013 Revenue Requirement Application	218	23	2	1	245
CCE CPCN Application	122	11	1	-	134
NGV for Transportation Application	74	-	-	-	74
Victoria Regional Office CPCN	-	-	-	-	-
Long Term Resource Plan Application	159	18	3	-	180
Total Mid Year Balance, Application Costs Deferrals	**$ 986**	**$ 72**	**$ 9**	**$ 1**	**$ 1,068**

6.3.4.1 Revenue Requirements and Long Term Resource Plan

FEI will incur costs in 2011 and 2012 to prepare various recurring applications such as the current Revenue Requirement Application and the Long Term Resource Plans. Costs incurred

[138] Section 7.1 to 7.4, Schedule 69 and 71

consist of legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. FEI is proposing to allocate 10 percent of these costs to Vancouver Island and 1 percent of these costs to Whistler, based on number of customers. Consistent with past practice, FEI proposes to defer the costs incurred in 2011 for recovery over 2012 and 2013 for the Revenue Requirement Application, and over two years beginning in 2013 for the Long Term Resource Plan application costs. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

The application cost deferral accounts pertaining to the 2010 and 2011 Revenue Requirements, the 2009 ROE and Cost of Capital and the CCE CPCN were approved by Commission Order No. G-141-09 for Mainland, Commission Order No. G-140-09 for Vancouver Island and Commission Order No.138-10 for Whistler and Commission Order No. G-27-11 for Fort Nelson. The 2010 and 2011 revenue requirement application costs are expected to be fully amortized by December 31, 2012 for Mainland, Vancouver Island and Whistler. The 2009 ROE and Cost of Capital and CCE CPCN costs have been amortized over five years in all of the Utilities and are expected to be fully amortized by December 31, 2014.

6.3.4.2 NGV for Transportation Application

In the NGV Application filed on December 1, 2010, FEI requested approval for a non-rate base deferral account attracting AFUDC to capture the NGV Fueling Service Application costs incurred in 2010 and 2011 and to recover these costs from all non-bypass customers by transferring the account to rate base and amortizing the balance through delivery rates commencing January 1, 2012 over a three year period. For purposes of determining its 2012 and 2013 revenue requirements, FEI has included this account and its amortization. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

6.3.4.3 Victoria Regional Centre CPCN

In accordance with Commission Order No. C-6-11, FEVI has captured application costs associated with the Victoria Regional Office Facility CPCN incurred in 2010 and 2011, in a deferral account. In this Application, FEVI is seeking approval to amortize the balance through rates in 2012. Any variances between the forecast account balances and the actual incurred costs will be amortization in rates starting in 2014.

6.3.5 OTHER DEFERRAL ACCOUNTS

The Utilities have included the following previously approved and new deferrals in rate base for 2012 and 2013:

Table 6.3-11: Balance in Other Deferrals Largely Due to Whistler Conversion[139]

2012 Forecast, Mid Year Balance, ($ thousands)					
Other Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Whistler Pipeline and Conversion Costs	$ -	$ -	$ 12,918	$ -	$ 12,918
Whistler Capital Contribution to Vancouver Island	-	-	13,724	-	13,724
Pipeline Contribution Costs Variance Account	-	-	(217)	-	(217)
Pension & OPEB Funding	(57,749)	(11,283)	-	-	(69,032)
Deferred Removal Costs	2,184	336	3	-	2,522
Gains and Losses on Asset Disposition	11,064	1,016	72	96	12,249
IFRS Transitional	27,834	5,699	-	-	33,533
PCEC Start Up Costs	-	1,030	-	-	1,030
2010-2011 Customer Service O&M and COS	23,385	2,627	251	-	26,264
2011 Kootenay River Crossing COS	100	-	-	-	100
Gas Asset Records Project	534	60	6	-	600
BC OneCall Project	334	38	4	-	375
Total Mid Year Balance, Other Deferrals	**$ 7,686**	**$ (477)**	**$ 26,761**	**$ 96**	**$ 34,065**

2013 Forecast, Mid Year Balance, ($ thousands)					
Other Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Whistler Pipeline and Conversion Costs	$ -	$ -	$ 12,178	$ -	$ 12,178
Whistler Capital Contribution to Vancouver Island	-	-	13,435	-	13,435
Pipeline Contribution Costs Variance Account	-	-	-	-	-
Pension & OPEB Funding	(92,858)	(16,269)	-	-	(109,127)
Deferred Removal Costs	728	112	1	-	841
Gains and Losses on Asset Disposition	10,497	964	69	91	11,621
IFRS Transitional	52,098	10,935	-	-	63,032
PCEC Start Up Costs	-	986	-	-	986
2010-2011 Customer Service O&M and COS	21,940	2,465	237	-	24,642
2011 Kootenay River Crossing COS	60	-	-	-	60
Gas Asset Records Project	1,535	173	17	-	1,725
BC OneCall Project	918	103	10	-	1,031
Total Mid Year Balance, Other Deferrals	**$ (5,082)**	**$ (532)**	**$ 25,947**	**$ 91**	**$ 20,423**

6.3.5.1 Whistler Pipeline and Conversion Costs

Pursuant to Commission Order No. G-53-06, Commission Order No. G-35-09 and Commission Order No. G-138-10, Whistler maintains four deferral accounts related to pipeline and conversion costs that began amortizing in delivery rates effective January 1, 2010, over a 20 year period. No further additions will occur to these accounts.

For presentation purposes[140], Whistler has summarized the pipeline and conversion cost accounts into one account as shown in Table 6.3-12.

[139] Section 7.1 to 7.4, Schedule 69 and 71
[140] Whistler will continue to maintain the five deferral accounts related to pipeline and conversion costs separately

Table 6.3-12: Whistler Pipeline and Conversion Cost Accounts Summarized

Deferral Account, ($ thousands)	2012 Mid Year Balance	Annual Amortization	Amortization Years	Account Description
Natural Gas Pipeline Development Costs	$ 1,651	$ (94)	20	Project development costs
Decommissioning of Propane Assets	4,068	(232)	20	NBV of the propane assets (net of the land sold)
Capital Gain on Sale of Propane Land	(466)	27	20	Gain on the sale of the land
Direct Customer Appliance Conversion Costs	7,665	(441)	20	Appliance conversion costs
Whistler Pipeline and Conversion Costs	$ 12,918	$ (740)		

6.3.5.2 Whistler Capital Contribution to Vancouver Island

To the extent that FEW toll revenues are less than the marginal cost of service of the Whistler Pipeline, FEW is required to make a Capital Contribution to FEVI to leave the existing FEVI customers unaffected by the construction of the Whistler Pipeline. As per Commission Orders No. G-53-06, G-76-06, G-35-09 and G-138-10, the contribution amount is to be determined upon the completion of the Whistler Pipeline and the determination of final pipeline costs. The contribution is amortized in Whistler delivery rates over 50 years, commencing January 1, 2010. In accordance with Commission Order No. G-138-10, amortization based on a forecast capital contribution of $17.0 million was included in the interim 2010 and 2011 Whistler delivery rates.

As of the filing date of this Application, the determination of final pipeline costs remains outstanding. In this Application, FEW has estimated the final amount of the contribution at $14.6 million and has adjusted the January 1, 2012 opening balance in the deferral account accordingly. The impact of the approximate $2.5 million variance between the contribution of $14.6 million and the contribution of $17.0 million included in the 2010 and 2011 delivery rates is captured in the Pipeline Contribution Costs Variance Account discussed below.

6.3.5.3 Pipeline Contribution Costs Variance Account

On April 14th, 2011, FEW submitted an Application for Permanent Rates for 2010 and 2011, where it proposed the creation of a rate-base deferral account, entitled “Pipeline Contribution Cost Variance Deferral Account” to record any differences between:

a) the cost of service from April of 2009 to December 31, 2011, associated with the Pipeline Contribution that is included in the calculation of the interim rates ($17.034 million); and

b) the cost of service from April of 2009 to December 31, 2011 associated with the final Pipeline Contribution amount ($14.550 million).

On April 21, 2011, the Commission approved the creation of the deferral account in Order No. G-71-11. The forecast balance in this account is amortized in delivery rates over one year, commencing January 1, 2012. Differences, if any, in cost of service for 2010 and 2011 resulting from the final determination of the actual Pipeline Contribution when known will be captured in this deferral account, for disposition in a future revenue requirements application.

6.3.5.4 Pension and OPEB Funding

This account records the difference between amounts funded by ratepayers for pension and OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis. Amounts funded by ratepayers through both pension and OPEBs through the collection of actuarially-determined expense amounts in rates, but not yet paid out by the Company, should be included in deferrals and be a component of rate base. It also follows that any amounts funded by the Company in advance of being funded by ratepayers would also be included in a rate base deferral.

This treatment was approved by Commission Order No. G-135-99 and Commission Order No. G-141-09 for Mainland and by Commission Order No. G-140-09 for Vancouver Island.

6.3.5.5 Deferred Removal Costs

In accordance with Commission Order No. G-141-09 for Mainland, Commission Order No. G-140-09 for Vancouver Island, Commission Order No. G-138-10 for Whistler and Commission Order No. G-27-11 for Fort Nelson, the Companies removed the provision for net negative salvage from depreciation estimates and included a forecast of the actual amount of net removal costs in the 2010 and 2011 cost of service.

As agreed upon, for 2010 and 2011, the Deferred Removal Cost account was set up to capture any variances between the actual amount of net removal costs realized and the estimated amounts included in the cost of service. As discussed in Section 5.6.6.2, the Companies determined that it is reasonable to deduct removal costs in the year incurred for income tax purposes and accordingly have recorded this account on a net of tax basis. The amount accumulated in this account was to be recovered from or returned to customers through rates in 2012; however, due to the magnitude of the balances the Companies believe that two years is an appropriate amortization period for this account and accordingly, are seeking approval to amortize the balance in delivery rates over 2 years, beginning January 1, 2012.

6.3.5.6 Gains and Losses on Asset Disposition

IFRS require that gains and losses on disposal of assets be recognized in the income statement. As approved by Commission Order No. G-141-09 for Mainland, Commission Order No. G-140-09 for Vancouver Island and Commission Order No. G-138-10 for Whistler, the Companies will continue to defer the amount of these gains and losses during the term of this Application, for recovery in future years. The Companies do not forecast gains or losses on asset disposals; however, we request Commission approval for any gains and losses incurred during 2012 and 2013 to be included in this rate base deferral account, consistent with the treatment in 2010 and 2011.

In this Application the Companies are seeking approval to transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on

Asset Disposition account and to amortize the total balance in this account in delivery rates over 20 years, aligned with the average service life of the asset categories that are contributing to the losses.

6.3.5.7 IFRS Transitional Adjustments

In their 2010-2011 RRAs, the Utilities had forecast the adoption of IFRS in 2011. Under IFRS there is a one-time reset of the net pension asset/liabilities, resulting in any unamortized actuarial losses, past service cost and transitional obligations being recognized in retained earnings. Consistent with the approved treatment in the 2010-2011 RRAs, the Utilities have recorded this one-time adjustment in the IFRS Transitional Deferral Account, but due to the one-year deferral of adoption of IFRS, the entry has been made as of January 1, 2012 instead of January 1, 2011 as originally forecast. Table 6.3.13 below shows the composition of this entry for the Mainland and Vancouver Island.

Table 6.3-13: Pension and OPEB Transitional Adjustment on Adoption of IFRS

($ thousands)

	Transitional Amount			EARSL	
	Pension	OPEB	Total	Pension	OPEB
Mainland- M&E Legacy Plan	$ 19,470			6	
Mainland- M&E TI Plan	(1,202)			11	
Mainland- Cope and IBEW Plan	31,514			10	
Mainland	49,782	13,024	62,806		13
Vancouver Island	8,078	4,247	12,325	13	14
FortisBC Energy Utilities	$ 57,860	$ 17,271	$ 75,131		

The Utilities have considered alternative methods to amortize this IFRS Transitional Adjustment into delivery rates. We have selected the expected average remaining service life ("EARSL") by plan, to amortize this obligation over, since it results in a similar total expense to what would have been recorded under Canadian GAAP. These amounts have been included in amortization expense in the calculation of the cost of service. The status of transitioning to IFRS is addressed in Section 3.2.1 along with any deferral account impacts.

6.3.5.8 PCEC Start Up Costs

The PCEC Start Up Costs deferral includes the unrecovered balance of the original amount of pre-start up costs of $1,754,000 incurred by PCEC to operate a portion of the Vancouver Island pipeline facilities for several months prior to the "in-service" date of October 1, 1991. Vancouver Island began amortizing these costs over 40 years on October 1, 1994 in accordance with the Binding Agreement.

6.3.5.9 2010-2011 Customer Service O&M and Cost of Service

Pursuant to Commission Order No. C-1-10, Commission Order No. G-23-10 and Commission Order No. G-141-09, FEI has transferred the Customer Care Enhancement Project non-rate base deferral account to rate base effective January 1, 2012. This account captures the costs associated with the Project incurred prior to the project implementation and go live date of January 1, 2012 in addition to project costs expected to be incurred in the early months of 2012.[141] In this application FEI is seeking approval to allocate the balance in this deferral account amongst the FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The Companies are seeking approval to amortize this account in delivery rates over eight years, the same amortization period that was used in the CCE Project CPCN Application.

6.3.5.10 2011 Kootenay River Crossing Cost of Service

As approved by Commission Order No. C-9-10, FEI has transferred the Kootenay River Crossing Cost of Service non-rate base account to rate base effective January 1, 2012. This account captures the October through December 2011 cost of service related to the plant in service, consisting of depreciation expense, income taxes and earned return and is amortized in delivery rates over a three year period commencing January 1, 2012. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates starting in 2014.

6.3.5.11 Gas Asset Records Project

Governments, Regulators, codes, and best practices have always required that pipeline operators collect, retain and manage records pertaining to their gas system assets. Due to more recent events and resulting public pressure, more stringent requirements have been put in place related to the collection, retention and management of gas system asset records. Along with industry, the FEU must continue to invest to ensure we meet the gas system records collection, retention and management requirements of the codes, regulations and standards that govern our business. The paragraphs that follow provide a summary of what is driving our specific records related actions, what steps we have taken in the last few years, and what we still need to do.

At this time, there are four key external drivers that are prompting the FEU to pursue more rigorous actions with their gas system records. First, on January 17, 2011, The OGC issued a Safety Advisory informing all pipeline operators in BC of their requirements under CSA Z662-07 with respect to records. The Advisory states that;

[141] The approved project costs as per Commission Order No. C-1-10 and Commission Order No. G-23-10 include deferred O&M of approximately $5 million in 2012.

> *In light of the San Bruno incident, the Commission reminds Pipeline Permit Holders that they must develop and maintain records of materials used within their pipeline system as part of their permanent records as per clause 5.7.1 of CSA Z662. The Commission recognizes that over time records may become damaged or lost due to causes beyond the Permit Holder's control. In such instances, the Commission expects that Permit Holders will have plans and programs in place for the management of their pipeline system in the absence of these records as well as programs for reestablishment of the records.*[142]

Second, on the same day, the OGC issued a directive to pipeline operators informing them of the OGC's Integrity Management Programs Self Assessment Protocols and Regulatory Process[143]. Under Section 6 of the Self Assessment form, the following requirement is specified.

> *The permit holder must establish, implement and maintain a records management program encompassing the creation, security, updating, retention, retrieval and deletion of all information and records necessary for the execution of the IMP. Permit holders are required to maintain all records as required within Annex N and within the broader context of CSA Z662. Where records are incomplete due to asset transfers or other reasons, the permit holder should acknowledge this in their self assessment and provide information on how the IMP manages in the absence of these records as well as how these records are being recovered.*[144]

Third, the Association of Professional Engineers of British Columbia ("APEGBC") has recently amended its Bylaws to expand the scope of its quality management clause. The new clause states that:

> *Members and licensees shall establish and maintain documented quality management processes for their practices, which shall include, as a minimum:*
>
> > *(1) retention of complete project documentation which may include, but is not limited to, correspondence, investigations, surveys, reports, data, background information, assessments, designs, specifications, field reviews, testing information, quality assurance documentation, and other engineering and geoscience documents for a minimum period of 10 years*[145]*;*

As seen above, the recent San Bruno gas pipeline explosion in September 2010, has led to a focus on the importance of gas system asset records. Even though the results of the various

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[142] BC Oil and Gas Commission Safety Advisory 2011-01, January 17, 2011, Records Requirements for Pipelines
[143] BC Oil and Gas Commission Safety Advisory 2011-01, January 17, 2011, Records Requirements for Pipelines
[144] OGC Self Assessment Protocol – Integrity Management Programs for Pipeline Systems; OGC website
[145] http://www.apeg.bc.ca/resource/publications/governancepolicies/documents/bylaws.pdf

investigations and inquiries into the explosion are still pending, it appears that the lack of historical records for the pipeline in question played a key role in the incident.

The FortisBC Energy Utilities have been and will continue to be diligent about the collection, retention and management of gas system records. We have records in various systems, locations and formats dating back to the original construction of our gas systems. Recognizing the challenges presented by such disparate systems, locations and formats, we have been focusing on capturing all of our critical gas system asset compliance records into a formal and rigorous management system. In 2006, we implemented a pilot records project to test a Filenet[146] implementation for gas system asset records. Issues were identified and solutions developed thorough 2007 and 2008. In 2009, we successfully implemented a customized Filenet solution which includes a governance framework, and a sustainment organization for gas system asset compliance records. Gas system asset compliance records resulting from new gas system asset projects continue to be prudently managed in accordance with policy and regulatory requirements. In short, we have been actively pursuing strategic improvements to our collection, retention and management of our gas system records and, as explained below, we intend to continue with these improvements.

In 2010 and early 2011, the FEU undertook a review of and planning for its handling of historic gas system asset compliance records. The 2010/11 review and planning led to the development of three distinct projects which will improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records, and the retention and disposal of compliance records no longer needed for operational, or other requirements. These projects follow a phased and consistent approach to move historic gas system asset compliance records into Filenet. The historic gas system asset compliance records funding sought for 2012, 2013 and beyond will permit the Utilities to manage historic gas system asset compliance records and provide ready access, authenticity, security and disposition. It will also ensure that compliance records are correctly assigned to the asset and, in the case of drawings, confirm that all appropriate drawings are in place.

To take the collection, retention and management of our gas system asset compliance records to the next level of performance, we are seeking approval for the creation of a deferral account to capture and recover the costs of this project, as outlined in Table 6.3-14 below. The costs to be incurred under this Project are one time in nature and have lasting value for customers, and are more appropriately reflected in a deferral account than through an increase in the base level of O&M. This will allow the Utilities to spread the costs out over a longer period better matching with the period that benefits will be realized.

The project will consist of three distinct components. Project “A” will consolidate and scan or move vital records from various locations (paper and electronic based) into one electronic

[146] FileNet is an IBM software application that we are using for the secure capture, retention and management of gas system asset compliance records.

management system (Filenet). It will be implemented approximately equally over four years (2012 - 2015) using internal resources and an external scanning service. When completed, we will have processed the following records:

1. Pipeline Design Files (60 File Drawers)
2. Offsite Files - Project Files located in Interior offices (200 File Drawers)
3. Iron Mountain Files - Previous Engineers' Files (200 Boxes = 100 File Drawers)
4. Iron Mountain Files - OGC Reconciliation Project Files (30 boxes = 15 File Drawers)
5. Shared Drive - OGC Historic Certificate Files (Vancouver Island)

Project 'B' will review and improve the management and control systems related to engineering drawings management to support ongoing sustainment of a single set of current and as built drawings for assets. The review and improvement in the management and control systems will be undertaken to support the revised OGC and APEGBC requirements.

Project 'C' will review historical drawings to determine the best available complete and current set of drawings for each asset. Under this project we estimate that it will be necessary to index and scan approximately 50,000 hard copy drawings into Filenet, and index and move approximately 100,000 drawings from the shared drive into Filenet. We have taken great care to break this project down into manageable components to achieve a successful outcome.

Table 6.3-14: Forecast Costs for Gas Assets Records Project

	2012	2013	2014	2015
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	1,150,000	1,150,000	1,130,000	400,000
Project 'B' – Implement improved drawing management & control systems	350,000	275,000		
Project 'C' - Review & analyze historical drawings	550,000	870,000	1,050,000	1,400,000
Total	2,000,000	2,250,000	2,150,000	1,400,000

In summary, due to more recent events and resulting public pressure, the actions of Governments, Regulators, and Associations are sending a clear and direct signal to pipeline operators with respect to their gas system asset compliance records. That directive is to ensure that gas system asset compliance records are indeed collected, retained and managed prudently. The FEU has been working diligently for quite some time on the management of our gas system asset compliance records. We introduced the FileNet technology, reviewed and assed the state of our historic records and are now seeking funding to complete the work we started in a timely and systematic manner.

To continue to meet the records management requirements of the codes, regulations and standards that govern our business, we are requesting approval for up to $7.8 million for the four year period ending December 31, 2015 and to manage these costs within the framework of a deferral account mechanism, to be amortized in delivery rates over five years, commencing January 1, 2012. FEU believe that a five year amortization period is appropriate because it mitigates the rate impacts of the costs and generally coincides with the period over which the costs are incurred. The $7.8 million is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. Furthermore, FEI is seeking approval to allocate the balance in this deferral account amongst FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The 2012 and 2013 forecasts as provided in Table 6.3-14 have been included in the deferral account for the purposes of determining the revenue requirements in this Application.

6.3.5.12 BCOneCall Project

The external environment around BCOneCall has been evolving and shifting since its inception in 1994. The corresponding actions of Government, the Regulator and industry have brought new requirements to the operations of many individual organizations. In response, we have implemented many successful initiatives in the past and we must build on those successes to take the FEU BCOneCall process to the next level of performance. As such, we need to fund a multi-stream project that will automate a portion of the BCOneCall process and allow us to realize significant benefits immediately upon completion of the project. The following sections describe the current state, the future state, the drivers for the project, the scope of work, and the benefits that are forecast to be realized.

Presently, the BCOneCall process is a "manual" process despite the use of software applications and technology. All BCOneCall tickets go through the same rigorous and labour intensive process. Location Records ticket processing staff use various technologies (SAP, AMFM[147], SIA[148], DCRS[149], and TelDig[150]) to identify the location and the nature of the request and then use these technologies to assemble the package of information that is sent to excavators. Even though different applications are involved, the current operating model is manually driven.

In the future, the processing of BCOneCall tickets will be significantly automated as determined by the nature of the request. The various technologies, SAP, AMFM, SIA, DCRS, and TelDig will be integrated and aligned such that they will automatically assemble certain BCOneCall

[147] AMFM is short for Asset Management/Facilities Management and refers to our GIS system.
[148] SIA is short for Service Information Application and is where we store the alpha numeric service data that is used to produce service lists and provide general service information.
[149] DCRS is short for Digitized Construction Records System and is where the actual copy of the service document resides in digital format.
[150] Teldig is the name of the company that provides the software we use for processing BC One Call tickets

packages with little or no human intervention. Following a Quality Assurance (QA)/Quality Control (QC) process, these assembled packages will then be sent to customers. Automation will be maximized and human intervention will be minimized in the new operating model.

The key drivers that influence the decision to proceed with this project at this time are:

- The Utilities have been continuously managing the efficiency and effectiveness of the BCOneCall process and this project is the next major step in that journey. This project will improve our ability to process increasing numbers of BCOneCall tickets more quickly and at a reduced unit cost in a sustainable and scalable manner.
- We expect our ticket volumes to continue to increase at 8 percent - 12 percent per year. Government, the BC Safety Authority, industry and individual organizations (including the FEU) are actively promoting the BCOneCall concept. Activities are in place to increase public and contractor awareness of BCOneCall and the requirement to "Call Before You Dig". The intended impact of these activities is to increase BCOneCall ticket volumes as much as possible and as quickly as possible.
- The current BCOneCall ticket processing operating model is not sustainable or scalable into the future. It is an inefficient model that takes a long time to ramp up production capacity to meet ticket volume demand.
- While we have no control over ticket volumes or their increase, we can control unit costs for processing tickets. As such, our only option is to establish an operating model that minimizes the response time and unit costs through the use of technology and automation.
- We believe that technology, municipal landbase and software integration capacity are at a state where we can achieve some degree of automation after we address key data related issues.

The scope of this project encompasses three streams - Technology, Data Consistency, and Conflation.

The Technology Stream of this project enhances and integrates technologies in a way that enables automatic classification of tickets in order to seamlessly process select groups of tickets. Most of the technology related work is on the AMFM system. Minor enhancements are planned for the SAP, SIA, and DCRS systems to allow them to continue to provide customer information but be more integrated with the other technologies to support the automation. Finally, TelDig is enhanced to perform the automatic assembly and dissemination of processed tickets. The Technology Stream will be completed by mid 2011 and is being funded through our IT capital process. The Technology Stream provides technology enhancements, integrations and process improvements necessary to automate a portion of the BCOneCall ticket process.

The intent of the Data Consistency Stream is to correct identified data inconsistency issues in order to reduce the numbers of exceptions requiring a stop to the BCOneCall process. For example, under this stream, we will ensure that we have consistent asset and customer data in our SIA system for all areas of the Province in order to be able to deploy automation Province wide. Improvement to the consistency of data consumed within the BCOneCall ticket process is one of the foundation elements of automation.

The Conflation Stream will import the most current landbase available for the FEI service territory and shift the FEI gas mains/assets so that they correctly align with this new landbase. This stream of the project is necessary because the gas mains in the AMFM system are attached to a landbase that is about 8 years old and somewhat out of date. Having the most current Municipal landbase is essential to the successful automation of the BCOneCall process.

Technology, consistent data, and current Municipal landbase are foundational to the success of our automation of the BCOneCall process. The Technology Stream is implementing the technology that will enable the automation, while the Data Consistency Stream and Conflation Stream will ensure that we have consistent data and current landbase in our various systems to reduce exceptions to the process.

The BCOneCall Ticket Process Improvement project offers a significant financial benefit that will see a reduction in our long term O&M costs required for processing BCOneCall tickets. The source of this financial benefit is from the direct reduction of the average ticket processing time by up to 34.7 percent as a result of automation. This equates to a decrease in processing time of up to 10.9 minutes (from the current average of 31.5 minutes). This processing time reduction is estimated to result in an average $540 thousand annual sustainable O&M savings per year after 2014 - once the project is fully implemented and stabilized.

Once approved, the project is expected take two and half years to fully implement and to stabilize. We are forecasting a budget of $2.3 million dollars to fund the project as shown in the table below for each of the streams.

Table 6.3-15: BC One Call Ticket Process Improvement Project Costs

($ thousands)

Stream	2012	2013	2014	Total
Technology Stream	$ 96	$ -	$ -	$ 96
Data Consistency Stream	760	510	-	1,270
Conflation Stream	375	375	190	940
Total	**$ 1,231**	**$ 885**	**$ 190**	**$ 2,306**

We are requesting approval to manage these costs within the framework of a deferral account mechanism, to be amortized in delivery rates over five years, commencing January 1, 2012. FEU believe that a five year amortization period is appropriate because it mitigates the rate impacts of the costs and generally coincides with the period over which the costs are incurred. The $2.3 million is an estimate of the total project costs; only the actual project costs will be recorded in the deferral account and ultimately recovered from customers. The costs to be incurred under this Project are one time in nature and have lasting value for customers, and are more appropriately reflected in a deferral account than through an increase in the base level of O&M. This will allow the Utilities to spread the costs out over a longer period better matching with the period that benefits will be realized. Furthermore, FEI is seeking approval to allocate the balance in this deferral account amongst FortisBC Energy Utilities on the basis of average customers, resulting in an allocation of 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. The 2012 and 2013 forecasts as provided in Table 6.3-15 have been included in the deferral account for the purposes of determining the revenue requirements in this Application.

6.3.6 RESIDUAL DEFERRAL ACCOUNTS

The Utilities have included the following previously approved Residual deferrals in rate base for 2012 and 2013:

Table 6.3-16: Forecast 2012 and 2013 Residual Deferral Accounts[151]

2012 Forecast, Mid Year Balance, ($ thousands)					
Residual Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
SCP Tax Reassessment	$ 684	$ -	$ -	$ -	$ 684
Other	(63)	-	(23)	-	(86)
Residual Delivery Rate Riders	89	-	-	-	89
Mid Year Balance, Residual Deferral Accounts	**$ 711**	**$ -**	**$ (23)**	**$ -**	**$ 688**

2013 Forecast, Mid Year Balance, ($ thousands)					
Residual Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
SCP Tax Reassessment	$ 684	$ -	$ -	$ -	$ 684
Other	-	-	-	-	-
Residual Delivery Rate Riders	-	-	-	-	-
Mid Year Balance, Residual Deferral Accounts	**$ 684**	**$ -**	**$ -**	**$ -**	**$ 684**

6.3.6.1 Southern Crossing Pipeline Tax Reassessment

FEI continues to hold an amount for reassessment of PST related to the SCP project in a rate base deferral account, as approved by Commission Orders No. G-160-06 and G-153-07. In 2007, the Province of B.C. reassessed the Company for provincial sales tax related to the SCP project. The Company had made a deposit of $7.043 million in respect of this matter. During 2010, the B.C. Court of Appeal decided the appeal in the Company's favour. In August 2010, the Company received a refund of $7.049 million, representing a refund of the Company's

[151] Section 7.1 to 7.4, Schedule 69 and 71

deposit plus interest of $647 thousand. However, the Province reassessed PST of $641 thousand on a different matter related to the SCP project and reduced the refund by this amount. This reassessment relates to the lease payments made by the Company in respect of pipe and compressor assets of the SCP.

The Company has appealed this reassessment of $641 thousand and if the Company is successful in its appeal, the amount will be refunded. If the Company is unsuccessful, an additional amount of $265 thousand plus interest could be assessed for the period from July 2007 to June 2010 which was not included in the assessment made during 2010.

The balance in the deferral account is comprised of the following amounts:

Table 6.3-17: SCP Reassessment 2012 Opening Account Balance

	($ Million)
Original Assessment	7.043
Legal and consulting fees net of tax	0.505
	7.548
Refund, Original Assessment	(7.043)
Refund, Interest net of tax	(0.462)
	(7.505)
2010 Reassessment	0.641
Opening Balance, 2012	0.684

FEI expects that this issue will be resolved within the 2012 and 2013 forecast period, after which time the Company will seek a Commission order with respect to the disposition of the deferral account.

6.3.6.2 Other

A number of deferral accounts were created for specific purposes during the term of the last RRA and previous PBR periods that are expected to be fully amortized by December 31, 2012. The Companies will be discontinuing the use of the following deferral accounts after the amounts are amortized in 2012.

- Mainland Carbon Tax Cost of Service
- Mainland OSC Certification Compliance
- Whistler Deferred ROE Variance

- Whistler 2009 Revenue Requirement Application Costs

6.3.6.3 Residual Delivery Rate Riders

FEI is seeking approval to combine three residual non-rate base deferral account balances into one account, the Residual Delivery Rate Riders account, and to recover the balance through delivery rates in 2012. The residual balances in the ROE Revenue Requirement Variance Account (Rate Rider 2) and the Lochburn Land Costs and Delivery Rate Refund Rider accounts (both accounts used Rate Rider 4) are a result of volume variances (the actual volumes for recovery of the riders differed from what was forecast). Approved by Commission Order No. G-158-09, delivery Rate Rider 2 captured the 2009 recoveries associated with the 2009 ROE and Capital Structure Decision and applied to all non-bypass customers. Approved by Commission Order No. G-116-07, delivery Rate Rider 4 was in place April 1, 2008 through March 31, 2009 and captured a refund associated with the sale of land at the Lochburn facilities and applied to all non-bypass customers. Approved by Commission Order No. G-23-09, Rate Rider 4 remained in place April 1, 2009 through December 31, 2009 to refund the balance in the Delivery Rate Refund Rider account to all non-bypass customers. The Delivery Rate Refund Rider account resulted from the recalculation of 2009 delivery rates.

6.3.7 SUMMARY OF DEFERRAL ACCOUNTS

The Companies believe that the deferral accounts requested above serve to add value to customers and our shareholder and appropriately address uncontrollable matters and significant non-recurring items.

In this application, the Companies are requesting approval for eight new rate base deferral accounts, the setting of, or modification to, the amortization period of eleven rate base deferral accounts, as well as additional requests or changes to five existing rate base deferral accounts. Table 6.3-18 provides a summary of the request for approvals in this Application related to all rate base deferral accounts.

Table 6.3-18: Summary of 2012 and 2013 Deferral Account Requests

Type of Change	Account	Company	Reference
New Account	Compliance to Emission Regulations	FEU	Section 6.3.2.3; Additions and Amortization period TBD
	Customer Service Variance Account	FEU	Section 6.3.3.10; Additions and Amortization period TBD
	Vancouver Island Joint Venture Litigation Costs	FEVI	Section 6.3.3.11; amortization period of 1 year commencing January 1, 2012

Type of Change	Account	Company	Reference
	2012-2013 Revenue Requirement Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2012, allocated to FEU based on average customers
	Long Term Resource Plan Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2013, allocated to FEU based on average customers
	Gas Assets Records Management Project	FEU	Section 6.3.5.11; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	BCOneCall Project	FEU	Section 6.3.5.12; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	Residual Delivery Rate Riders	FEI	Section 6.3.6.3; amortization period of 1 year commencing January 1, 2012
Amortization Period Change- New or Modified	Revenue Stabilization Account Mechanism	FEW	Section 6.3.1.3; recovery through Rate Rider 5, 3 year recovery period consistent with FEI and FN, commencing January 1, 2012
	Gas in Storage Interest	FEI	Section 6.3.1.4; 3 year amortization period, commencing January 1, 2012
	Property Tax Variance Account	FEW, FN	Section 6.3.3.1; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Tax Variance Account	FEW	Section 6.3.3.6; 1 year amortization period, commencing January 1, 2012
	Vancouver Island HST Implementation	FEVI	Section 6.3.3.7; 1 year amortization period, commencing January 1, 2012
	Victoria Regional Centre CPCN	FEVI	Section 6.3.4.3; 1 year amortization period, commencing January 1, 2012
	Pipeline Contributions Variance Account	FEW	Section 6.3.5.3; 1 year amortization period, commencing January 1, 2012
	Deferred Removal Costs	FEU	Section 6.3.5.5; 2 year amortization period, commencing January 1, 2012
	IFRS Transitional Account	FEI, FEVI	Section 6.3.5.7; amortization by plan over EARSL
	2010-2011 Customer Service O&M and Cost of Service	FEU	Section 6.3.5.9; 8 year amortization period, commencing January 1, 2012

Type of Change	Account	Company	Reference
Other	Energy Efficiency and Conservation	FEU	Section 6.3.2.1; 1. Combined EEC rate base deferral account additions of \$20.0 million in 2012 and \$20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period; 2. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis; 3. The creation of the EEC Incentive non-rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.
	GCVA	FEVI	Section 6.3.1.6; continuation of the account for 2012 and 2013
	CNG and LNG Service Costs and Recoveries	FEI	Section 6.3.2.6; inclusion of variations from the revenue forecast pertaining to Rate Schedule 16
	Property Tax Variance Account	FEW	Section 6.3.3.1; include the forecast balance of the existing Propane Plant Property Tax Deferral account in the Property Tax Variance account
	Tax Variance Account	FEI	Section 6.3.3.6; inclusion of LILO reassessment costs
	Gains and Losses on Asset Disposition	FEU	Section 6.3.5.6; transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on Asset Disposition account; 20 year amortization period, commencing January 1, 2012

7 FINANCIAL SCHEDULES

For historical information for each of the Companies please refer to Appendix D.

7.1 Mainland Schedules

Summary of Rate Change May 4, 2011 Section 7
TAB 7.1
Schedule 1

Mainland

	2012 ($ Millions)		2013 ($ Millions)		Total ($ Millions)		Cross Reference
Volume/Revenue Related							
Customer Growth and Use Rates	$ (4.5)		$ (1.6)		$ (6.2)		
Change in Other Revenue	(2.8)	(7.3)	(1.7)	(3.3)	(4.5)	(10.7)	
O&M Changes							
Gross O&M Increases	9.4		12.4		21.8		
Less: Capitalized Overhead	(1.3)	8.1	(1.7)	10.6	(3.1)	18.7	
Depreciation & Removal Cost Provision							
Change in Depreciation Rates	4.6		-		4.6		
Tax Expense Impact of Depreciation Changes	7.5		2.0		9.5		
Depreciation from Net Additions	12.9		5.5		18.4		
Removal Cost Provision	4.9	29.9	0.5	8.0	5.5	37.9	
Amortization Expense							
CIAC	0.4		0.1		0.5		
Deferral Accounts	11.2	11.6	12.3	12.3	23.5	23.9	
Other							
Property and Other Taxes	(0.6)		1.6		1.0		
Other (NSP Provision, Transportation Costs)	(1.0)		-		(1.0)		
Income Tax Rate Change	(2.0)		(0.5)		(2.5)		
Other Income Tax Changes	(13.5)		4.1		(9.4)		
Financing Rate Changes	(4.4)		1.1		(3.3)		
Financing Changes	4.1		0.9		4.9		
Rate Base Growth	4.1	(13.3)	2.0	9.2	6.0	(4.2)	
Revenue Deficiency (Surplus)		**$ 29.0**		**$ 36.8**		**$ 65.8**	- Sect 7-TAB 7.1, Schedule 2 & 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Non-Bypass Sales	2012 Non-Bypass Transportation	2012 Bypass and Special Rates	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,215,335	$ 1,133,246	$ 71,171	$ 11,724	$ 1,216,141	$ 806	- Sect 7-TAB 7.1, Schedule 11
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / FortisBC Energy (Vancouver Island)	18,282	-	-	18,308	18,308	26	- Sect 7-TAB 7.1, Schedule 19
8								
9	Total Revenue	1,233,617	1,133,246	71,171	30,032	1,234,449	832	
10								
11	Less - Cost of Gas	(661,224)	(658,532)	(372)	(434)	(659,338)	1,886	- Sect 7-TAB 7.1, Schedule 13
12								
13	Gross Margin	$ 572,393	$ 474,714	$ 70,799	$ 29,598	$ 575,111	$ 2,718	
14								
15	Revenue Deficiency (Surplus)	$ -	$ 25,210	$ 3,760	$ -	**$ 28,970**	$ 28,970	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	5.31%	5.31%	0.00%	5.04%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	2.22%	5.28%	0.00%	2.35%		
20								

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Non-Bypass Sales	2013 Non-Bypass Transportation	2013 Bypass and Special Rates	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,216,141	$ 1,133,062	$ 72,221	$ 11,724	$ 1,217,007	$ 866	- Sect 7-TAB 7.1, Schedule 12
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / FortisBC Energy (Vancouver Island)	18,308	-	-	18,291	18,291	(17)	- Sect 7-TAB 7.1, Schedule 20
8								
9	Total Revenue	1,234,449	1,133,062	72,221	30,015	1,235,298	849	
10								
11	Less - Cost of Gas	(659,338)	(657,758)	(374)	(436)	(658,568)	770	- Sect 7-TAB 7.1, Schedule 13
12								
13	Gross Margin	$ 575,111	$ 475,304	$ 71,847	$ 29,579	$ 576,730	$ 1,619	
14								
15	Revenue Deficiency (Surplus)	$ 28,970	$ 57,122	$ 8,634	$ -	**$ 65,756**	$ 36,786	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.04%	12.02%	12.02%	0.00%	11.40%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	2.35%	5.04%	11.95%	0.00%	5.32%		
20								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	ENERGY VOLUMES (TJ)					
2	Sales	112,775	113,846	112,632	(1,214)	- Sect 7-TAB 7.1, Schedule 7
3	Transportation	88,336	91,014	93,355	2,341	- Sect 7-TAB 7.1, Schedule 7
4		201,111	204,860	205,987	1,127	
5						
6	Average Rate per GJ					
7	Sales	$ 10.861	$ 12.859	$ 10.067	$ (2.792)	
8	Transportation	$ 0.891	$ 0.856	$ 0.873	$ 0.017	
9	Average	$ 6.476	$ 7.527	$ 5.886	$ (1.641)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 1,224,870	$ 1,433,011	$ 1,133,872	$ (299,139)	- Sect 7-TAB 7.1, Schedule 10
13	- Increase / (Decrease)	-	30,953	-	(30,953)	
14	RSAM Revenue	(1,125)	-	(2,859)	(2,859)	
15	Transportation - Existing Rates	78,672	73,705	81,463	7,758	- Sect 7-TAB 7.1, Schedule 10
16	- Increase / (Decrease)	-	4,232	-	(4,232)	
17						
18	FEVI Revenue (Surplus) / Deficit	-	35,185	-	(35,185)	
19	**Total Revenue**	1,302,417	1,541,901	1,212,476	(329,425)	
20						
21	Cost of Gas Sold (Including Gas Lost)	762,338	989,627	661,224	(328,403)	- Sect 7-TAB 7.1, Schedule 13
22						
23	**Gross Margin**	540,079	552,274	551,252	(1,022)	
24						
25	Operation and Maintenance	177,614	184,625	184,625	-	- Sect 7-TAB 7.1, Schedule 21
26	Property and Sundry Taxes	49,193	50,211	50,211	-	- Sect 7-TAB 7.1, Schedule 24
27	Depreciation and Amortization	97,158	99,878	100,111	233	- Sect 7-TAB 7.1, Schedule 27
28	NSP Provisions	8,343	1,025	1,025	-	
29	Other Operating Revenue	(21,828)	(24,394)	(23,432)	962	- Sect 7-TAB 7.1, Schedule 18
30	Sub-total	310,480	311,345	312,540	1,195	
31	Utility Income Before Income Taxes	229,599	240,929	238,712	(2,217)	
32						
33	Income Taxes	31,152	32,516	31,335	(1,181)	- Sect 7-TAB 7.1, Schedule 30
34						
35	**EARNED RETURN**	$ 198,447	$ 208,413	$ 207,377	$ (1,036)	- Sect 7-TAB 7.1, Schedule 79
36						
37						
38	**UTILITY RATE BASE**	$ 2,525,213	$ 2,629,185	$ 2,535,745	$ (93,440)	- Sect 7-TAB 7.1, Schedule 39
39						
40	**RATE OF RETURN ON UTILITY RATE BASE**	7.86%	7.93%	8.18%	0.25%	- Sect 7-TAB 7.1, Schedule 79

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 ------ Revised Rates ------- Revised Revenue	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (2))	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,632	112,458	-	112,458	(174)	- Sect 7-TAB 7.1, Schedule 8
3	Transportation	93,355	94,258	-	94,258	903	- Sect 7-TAB 7.1, Schedule 8
4		205,987	206,716	-	206,716	729	
5							
6	Average Rate per GJ						
7	Sales	$ 10.067	$ 10.077	$ -	$ 10.301	$ 0.234	
8	Transportation	$ 0.873	$ 0.879	$ -	$ 0.919	$ 0.046	
9	Average	$ 5.886	$ 5.883	$ -	$ 6.023	$ 0.137	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,133,872	$ 1,133,246	$ -	$ 1,133,246	$ (626)	- Sect 7-TAB 7.1, Schedule 11
13	- Increase / (Decrease)	-	-	25,210	25,210	25,210	- Sect 7-TAB 7.1, Schedule 14
14						-	
15	Transportation - Existing Rates	81,463	82,894	-	82,894	1,431	- Sect 7-TAB 7.1, Schedule 11
16	- Increase / (Decrease)	-		3,760	3,760	3,760	- Sect 7-TAB 7.1, Schedule 14
17							
18	FEVI Revenue (Surplus) / Deficit	-	-	28,970	28,970	28,970	- Sect 7-TAB 7.1, Schedule 14
19	**Total Revenue**	1,212,476	1,216,140	28,970	1,245,110	32,634	
20							
21	Cost of Gas Sold (Including Gas Lost)	661,224	659,338	-	659,338	(1,886)	- Sect 7-TAB 7.1, Schedule 13
22							
23	**Gross Margin**	551,252	556,802	28,970	585,772	34,520	
24							
25	Operation and Maintenance	184,625	192,742	-	192,742	8,117	- Sect 7-TAB 7.1, Schedule 21
26	Property and Sundry Taxes	50,211	49,656	-	49,656	(555)	- Sect 7-TAB 7.1, Schedule 25
27	Depreciation and Amortization	100,111	133,920	-	133,920	33,809	- Sect 7-TAB 7.1, Schedule 28
28	NSP Provisions	1,025	-	-	-	(1,025)	
29	Other Operating Revenue	(23,432)	(27,203)	-	(27,203)	(3,771)	- Sect 7-TAB 7.1, Schedule 19
30	Sub-total	312,540	349,115	-	349,115	36,575	
31	Utility Income Before Income Taxes	238,712	207,687	28,970	236,657	(2,055)	
32							
33	Income Taxes	31,335	17,236	7,242	24,478	(6,857)	- Sect 7-TAB 7.1, Schedule 31
34							
35	**EARNED RETURN**	$ 207,377	$ 190,451	$ 21,728	$ 212,179	$ 4,802	- Sect 7-TAB 7.1, Schedule 80
36							
37							
38	**UTILITY RATE BASE**	$ 2,535,745	$ 2,736,462	$ 45	$ 2,736,507	$ 200,762	- Sect 7-TAB 7.1, Schedule 40
39							
40	**RATE OF RETURN ON UTILITY RATE BASE**	8.18%	6.96%		7.75%	-0.43%	- Sect 7-TAB 7.1, Schedule 80

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 ------ Revised Rates ------- Revised Revenue	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (2))	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,458	112,327	-	112,327	(131)	- Sect 7-TAB 7.1, Schedule 9
3	Transportation	94,258	94,833	-	94,833	575	- Sect 7-TAB 7.1, Schedule 9
4		206,716	207,160	-	207,160	444	
5							
6	Average Rate per GJ						
7	Sales	$ 10.301	$ 10.087	$ -	$ 10.596	$ 0.295	
8	Transportation	$ 0.919	$ 0.885	$ -	$ 0.976	$ 0.057	
9	Average	$ 6.023	$ 5.875	$ -	$ 6.192	$ 0.169	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,133,246	$ 1,133,062	$ -	$ 1,133,062	$ (184)	- Sect 7-TAB 7.1, Schedule 12
13	- Increase / (Decrease)	25,210	-	57,123	57,123	31,913	- Sect 7-TAB 7.1, Schedule 16
14						-	
15	Transportation - Existing Rates	82,894	83,945	-	83,945	1,051	- Sect 7-TAB 7.1, Schedule 12
16	- Increase / (Decrease)	3,760		8,633	8,633	4,873	- Sect 7-TAB 7.1, Schedule 16
17							
18	FEVI Revenue (Surplus) / Deficit	28,970	-	65,756	65,756	36,786	- Sect 7-TAB 7.1, Schedule 16
19	**Total Revenue**	1,245,110	1,217,007	65,756	1,282,763	37,653	
20							
21	Cost of Gas Sold (Including Gas Lost)	659,338	658,568	-	658,568	(770)	- Sect 7-TAB 7.1, Schedule 13
22							
23	**Gross Margin**	585,772	558,439	65,756	624,195	38,423	
24							
25	Operation and Maintenance	192,742	203,365	-	203,365	10,623	- Sect 7-TAB 7.1, Schedule 21
26	Property and Sundry Taxes	49,656	51,239	-	51,239	1,583	- Sect 7-TAB 7.1, Schedule 26
27	Depreciation and Amortization	133,920	152,235	-	152,235	18,315	- Sect 7-TAB 7.1, Schedule 29
28	NSP Provisions	-	-	-	-	-	
29	Other Operating Revenue	(27,203)	(28,883)	-	(28,883)	(1,680)	- Sect 7-TAB 7.1, Schedule 20
30	Sub-total	349,115	377,956	-	377,956	28,841	
31	Utility Income Before Income Taxes	236,657	180,483	65,756	246,239	9,582	
32							
33	Income Taxes	24,478	13,723	16,437	30,160	5,682	- Sect 7-TAB 7.1, Schedule 32
34							
35	**EARNED RETURN**	$ 212,179	$ 166,760	$ 49,319	$ 216,079	$ 3,900	- Sect 7-TAB 7.1, Schedule 81
36							
37							
38	**UTILITY RATE BASE**	$ 2,736,507	$ 2,787,899	$ 428	$ 2,788,327	$ 51,820	- Sect 7-TAB 7.1, Schedule 41
39							
40	**RATE OF RETURN ON UTILITY RATE BASE**	7.75%	5.98%		7.75%	0.00%	- Sect 7-TAB 7.1, Schedule 81

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Projected Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	70,041.0	68,578.9	70,003.0	-	70,003.0	1,424.1	
3	Schedule 2 - Small Commercial	23,620.0	24,603.1	23,544.7		23,544.7	(1,058.4)	
4	Schedule 3 - Large Commercial	16,393.0	17,168.5	16,423.2		16,423.2	(745.3)	
5								
6	Schedules 1, 2 and 3	110,054.0	110,350.5	109,970.9	-	109,970.9	(379.6)	
7								
8	Schedule 4 - Seasonal	185.0	184.6	185.2		185.2	0.6	
9	Schedule 5 - General Firm	2,464.0	3,184.3	2,407.7		2,407.7	(776.6)	
10								
11	Industrials							
12	Schedule 7 - Interruptible	11.0	22.7	11.7		11.7	(11.0)	
13								
14	Schedule 6 - N G V Fuel - Stations	61.0	103.8	56.4		56.4	(47.4)	
15								
16	Total Sales	112,775.0	113,845.9	112,631.9	-	112,631.9	(1,214.0)	- Sect 7-TAB 7.1, Schedule 4
17								
18	**TRANSPORTATION SERVICE**							
19	Schedule 22 - Firm Service	17,505.0	15,898.8	10,494.8	6,604.4	17,099.2	1,200.4	
20	- Interruptible Service	12,397.0	11,080.5	12,250.2	-	12,250.2	1,169.7	
21	Byron Creek (aka Fording Coal Mountain)	148.0	137.5		234.0	234.0	96.5	
22	Burrard Thermal - Firm	883.0	1,719.4		1,372.0	1,372.0	(347.4)	
23	FEVI - Firm	32,006.0	36,596.4		36,596.4	36,596.4	-	
24	Schedule 23 - Large Commercial	6,630.0	6,177.2	6,821.7		6,821.7	644.5	
25	Schedule 25 - Firm Service	12,785.0	13,817.2	12,073.0	949.7	13,022.7	(794.5)	
26	Schedule 27 - Interruptible Service	5,982.0	5,587.4	5,959.2		5,959.2	371.8	
27								
28	Total Transportation Service	88,336.0	91,014.4	47,598.9	45,756.5	93,355.4	2,341.0	- Sect 7-TAB 7.1, Schedule 4
29								
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	201,111.0	204,860.0	160,230.8	45,756.5	205,987.3	1,127.0	- Sect 7-TAB 7.1, Schedule 4

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars	2011 PROJECTED	2012 Forecast Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	70,003.0	69,890.0	-	69,890.0	(113.0)	
3	Schedule 2 - Small Commercial	23,544.7	23,438.1		23,438.1	(106.6)	
4	Schedule 3 - Large Commercial	16,423.2	16,469.5		16,469.5	46.3	
5							
6	Schedules 1, 2 and 3	109,970.9	109,797.6	-	109,797.6	(173.3)	
7							
8	Schedule 4 - Seasonal	185.2	185.2		185.2	-	
9	Schedule 5 - General Firm	2,407.7	2,407.7		2,407.7	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	11.7	10.8		10.8	(0.9)	
13							
14	Schedule 6 - N G V Fuel - Stations	56.4	56.4		56.4	-	
15							
16	Total Sales	112,631.9	112,457.7	-	112,457.7	(174.2)	- Sect 7-TAB 7.1, Schedule 5
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	17,099.2	11,006.1	6,210.8	17,216.9	117.7	
20	- Interruptible Service	12,250.2	12,227.1	-	12,227.1	(23.1)	
21	Byron Creek (aka Fording Coal Mountain)	234.0		230.7	230.7	(3.3)	
22	Burrard Thermal - Firm	1,372.0		1,372.0	1,372.0	-	
23	FEVI - Firm	36,596.4		36,847.2	36,847.2	250.8	
24	Schedule 23 - Large Commercial	6,821.7	7,151.3		7,151.3	329.6	
25	Schedule 25 - Firm Service	13,022.7	12,119.7	1,295.0	13,414.7	392.0	
26	Schedule 27 - Interruptible Service	5,959.2	5,798.0		5,798.0	(161.2)	
27							
28	Total Transportation Service	93,355.4	48,302.2	45,955.7	94,257.9	902.5	- Sect 7-TAB 7.1, Schedule 5
29							
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	205,987.3	160,759.9	45,955.7	206,715.6	728.3	- Sect 7-TAB 7.1, Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 FORECAST	2013 Forecast Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	69,890.0	69,816.4	-	69,816.4	(73.6)	
3	Schedule 2 - Small Commercial	23,438.1	23,331.9		23,331.9	(106.2)	
4	Schedule 3 - Large Commercial	16,469.5	16,514.8		16,514.8	45.3	
5							
6	Schedules 1, 2 and 3	109,797.6	109,663.1	-	109,663.1	(134.5)	
7							
8	Schedule 4 - Seasonal	185.2	185.2		185.2	-	
9	Schedule 5 - General Firm	2,407.7	2,407.7		2,407.7	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	10.8	14.2		14.2	3.4	
13							
14	Schedule 6 - N G V Fuel - Stations	56.4	56.4		56.4	-	
15							
16	Total Sales	112,457.7	112,326.6	-	112,326.6	(131.1)	- Sect 7-TAB 7.1, Schedule 6
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	17,216.9	11,020.6	6,068.9	17,089.5	(127.4)	
20	- Interruptible Service	12,227.1	12,302.6	-	12,302.6	75.5	
21	Byron Creek (aka Fording Coal Mountain)	230.7		227.4	227.4	(3.3)	
22	Burrard Thermal - Firm	1,372.0		1,372.0	1,372.0	-	
23	FEVI - Firm	36,847.2		37,080.0	37,080.0	232.8	
24	Schedule 23 - Large Commercial	7,151.3	7,485.3		7,485.3	334.0	
25	Schedule 25 - Firm Service	13,414.7	12,171.2	1,300.1	13,471.3	56.6	
26	Schedule 27 - Interruptible Service	5,798.0	5,804.8		5,804.8	6.8	
27							
28	Total Transportation Service	94,257.9	48,784.5	46,048.4	94,832.9	575.0	- Sect 7-TAB 7.1, Schedule 6
29							
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	206,715.6	161,111.1	46,048.4	207,159.5	443.9	- Sect 7-TAB 7.1, Schedule 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	**SALES**							
2	Schedule 1 - Residential	$ 803,239	$ 907,735	$ 750,208	$ -	$ 750,208	$ (157,527)	
3	Schedule 2 - Small Commercial	243,893	300,831	224,744		224,744	(76,087)	
4	Schedule 3 - Large Commercial	153,917	193,720	138,120		138,120	(55,600)	
5	Schedules 1, 2 and 3	1,201,049	1,402,286	1,113,072	-	1,113,072	(289,214)	
6								
7	Schedule 4 - Seasonal	1,485	1,477	1,263	-	1,263	(214)	
8	Schedule 5 - General Firm	21,632	28,009	18,921		18,921	(9,088)	
9		23,117	29,487	20,184	-	20,184	(9,303)	
10	Industrials							
11	Schedule 7 - Interruptible	115	194	116	-	116	(78)	
12								
13	Schedule 6 - N G V Fuel - Stations	589	1,044	500		500	(544)	
14								
15	Total Sales	1,224,870	1,433,011	1,133,872	-	1,133,872	(299,139)	- Sect 7-TAB 7.1, Schedule 4
16								
17	**Transportation Service**							
18	Schedule 22 - Firm Service	10,061	6,459	7,247	885	8,132	1,673	
19	- Interruptible Service	9,211	9,270	11,086	-	11,086	1,816	
20	Byron Creek (aka Fording Coal Mountain)	59	53		55	55	2	
21	Burrard Thermal - Firm	9,996	9,996		9,996	9,996	-	
22	FEVI - Firm	-	-		-	-	-	
23	Schedule 23 - Large Commercial	16,813	16,525	19,312	-	19,312	2,787	
24	Schedule 25 - Firm Service	25,115	24,744	24,561	766	25,327	583	
25	Schedule 27 - Interruptible Service	7,417	6,658	7,555	-	7,555	897	
26	Total Transportation Service	78,672	73,705	69,761	11,702	81,463	7,758	
27								
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,303,542	$ 1,506,716	$ 1,203,633	$ 11,702	$ 1,215,335	$ (291,381)	- Sect 7-TAB 7.1, Schedule 4

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 750,208	$ 750,035	$ -	$ 750,035	$ (173)	
3	Schedule 2 - Small Commercial	224,744	223,853		223,853	(891)	
4	Schedule 3 - Large Commercial	138,120	138,562		138,562	442	
5	Schedules 1, 2 and 3	1,113,072	1,112,450	-	1,112,450	(622)	
6							
7	Schedule 4 - Seasonal	1,263	1,263	-	1,263	-	
8	Schedule 5 - General Firm	18,921	18,921		18,921	-	
9		20,184	20,184	-	20,184	-	
10	Industrials						
11	Schedule 7 - Interruptible	116	112	-	112	(4)	
12							
13	Schedule 6 - N G V Fuel - Stations	500	500		500	-	
14							
15	Total Sales	1,133,872	1,133,246	-	1,133,246	(626)	- Sect 7-TAB 7.1, Schedule 5
16							
17	**Transportation Service**						
18	Schedule 22 - Firm Service	8,132	7,901	885	8,786	654	
19	- Interruptible Service	11,086	11,068	-	11,068	(18)	
20	Byron Creek (aka Fording Coal Mountain)	55		55	55	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	FEVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	19,312	20,228	-	20,228	916	
24	Schedule 25 - Firm Service	25,327	24,591	788	25,379	52	
25	Schedule 27 - Interruptible Service	7,555	7,382	-	7,382	(173)	
26	Total Transportation Service	81,463	71,170	11,724	82,894	1,431	
27							- Sect 7-TAB 7.1, Schedule 5
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,215,335	$ 1,204,416	$ 11,724	$ 1,216,140	$ 805	- Sect 7-TAB 7.1, Schedule 15

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 750,035	$ 750,275	$ -	$ 750,275	$ 240	
3	Schedule 2 - Small Commercial	223,853	222,969		222,969	(884)	
4	Schedule 3 - Large Commercial	138,562	139,001		139,001	439	
5	Schedules 1, 2 and 3	1,112,450	1,112,245	-	1,112,245	(205)	
6							
7	Schedule 4 - Seasonal	1,263	1,263	-	1,263	-	
8	Schedule 5 - General Firm	18,921	18,921		18,921	-	
9		20,184	20,184	-	20,184	-	
10	Industrials						
11	Schedule 7 - Interruptible	112	133	-	133	21	
12							
13	Schedule 6 - N G V Fuel - Stations	500	500		500	-	
14							
15	Total Sales	1,133,246	1,133,062	-	1,133,062	(184)	- Sect 7-TAB 7.1, Schedule 6
16							
17	**Transportation Service**						
18	Schedule 22 - Firm Service	8,786	7,952	885	8,837	51	
19	- Interruptible Service	11,068	11,101	-	11,101	33	
20	Byron Creek (aka Fording Coal Mountain)	55		55	55	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	FEVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	20,228	21,153	-	21,153	925	
24	Schedule 25 - Firm Service	25,379	24,625	788	25,413	34	
25	Schedule 27 - Interruptible Service	7,382	7,390	-	7,390	8	
26	Total Transportation Service	82,894	72,221	11,724	83,945	1,051	
27							- Sect 7-TAB 7.1, Schedule 6
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,216,140	$ 1,205,283	$ 11,724	$ 1,217,007	$ 867	- Sect 7-TAB 7.1, Schedule 17

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Projected Gas Costs Non-Bypass Sales & Transp	2011 Bypass and Special Rates	2011 Total	2012 Forecast Gas Costs Non-Bypass Sales & Transp	2012 Bypass and Special Rates	2012 Total	2013 Forecast Gas Costs Non-Bypass Sales & Transp	2013 Bypass and Special Rates	2013 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**SALES**									
2	Schedule 1 - Residential	413,828	$ -	$ 413,828	$ 413,141	$ -	$ 413,141	412,690	$ -	$ 412,690
3	Schedule 2 - Small Commercial	139,282		139,282	138,667		138,667	138,056		138,056
4	Schedule 3 - Large Commercial	92,298		92,298	92,569		92,569	92,840		92,840
5										
6	Schedules 1, 2 and 3	645,408	-	645,408	644,377	-	644,377	643,586	-	643,586
7										
8	Schedule 4 - Seasonal	986		986	986		986	986		986
9	Schedule 5 - General Firm	12,832		12,832	12,832		12,832	12,832		12,832
10										
11		13,818	-	13,818	13,818	-	13,818	13,818	-	13,818
12										
13	Industrials									
14	Schedule 7 - Interruptible	61		61	58		58	75		75
15										
16	Schedule 6 - N G V Fuel - Stations	279		279	279		279	279		279
17										
18										
19	Total Sales	659,566	-	659,566	658,532	-	658,532	657,758	-	657,758
20										
21	**TRANSPORTATION SERVICE**									
22	Schedule 22 - Firm Service	393	112	505	195	51	246	194	50	244
23	- Interruptible Service	93	1	94	45	-	45	45	-	45
24	Byron Creek (aka Fording Coal Mountain)		11	11		5	5		5	5
25	Burrard Thermal - Firm		27	27		13	13		13	13
26	FEVI - Firm		734	734		355	355		358	358
27	Schedule 23 - Large Commercial	71	-	71	36	-	36	38	-	38
28	Schedule 25 - Firm Service	142	15	157	68	10	78	69	10	79
29	Schedule 27 - Interruptible Service	59	-	59	28	-	28	28	-	28
30										
31	Total Transportation Service	758	900	1,658	372	434	806	374	436	810
32										
33	TOTAL SALES AND TRANSPORTATION SERVICES	$ 660,324	$ 900	$ 661,224	$ 658,904	$ 434	$ 659,338	$ 658,132	$ 436	$ 658,568
34										
35	Cross Reference			- Sect 7-TAB 7.1, Schedule 4			- Sect 7-TAB 7.1, Schedule 5			- Sect 7-TAB 7.1, Schedule 6

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

			Revenue -- At Existing 2011 Rates --		Gross Margin -- At Existing 2011 Rates --		Effective Increase / (Decrease) 5.31% of Margin			Revenue ------ Revised Rates -------	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000s)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000s)	Average Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,890.0	$ 10.714	$ 750,035	$ 4.813	$ 336,894	$ 0.256	$ 17,890	769,487	$ 10.970	$ 767,925
4	Schedule 2 - Small Commercial	23,438.1	9.508	223,853	3.618	85,187	0.192	4,524	76,086	9.700	228,377
5	Schedule 3 - Large Commercial	16,469.5	8.437	138,562	2.800	45,992	0.149	2,443	4,937	8.586	141,005
6	Schedules 1, 2 and 3	109,797.6		1,112,450		468,073		24,857	850,510		1,137,307
7											
8	Schedule 4 - Seasonal	185.2	6.820	1,263	1.501	278	0.081	15	18	6.901	1,278
9	Schedule 5 - General Firm	2,407.7	7.859	18,921	2.529	6,089	0.135	324	236	7.994	19,245
10											
11	Industrials										
12	Schedule 7 - Interruptible	10.8	9.573	112	4.615	54	0.171	2	4	9.744	114
13											
14	Schedule 6 - N G V Fuel - Stations	56.4	8.865	500	3.918	221	0.213	12	21	9.078	512
15											
16	Total Sales	112,457.7		1,133,246		474,715		25,210	850,789		1,158,456
17											
18	TRANSPORTATION SERVICE										
19	Schedule 22 - Firm Service	11,006.1	0.753	7,901	0.734	7,707	0.039	409	14	0.792	8,310
20	- Interruptible Service	12,227.1	0.904	11,069	0.900	11,024	0.048	586	21	0.952	11,655
21	Schedule 23 - Large Commercial	7,151.3	2.965	20,228	2.960	20,192	0.157	1,072	1,445	3.122	21,300
22	Schedule 25 - Firm Service	12,119.7	2.037	24,591	2.031	24,522	0.108	1,303	550	2.145	25,894
23	Schedule 27 - Interruptible Service	5,798.0	1.239	7,382	1.234	7,354	0.065	390	101	1.304	7,772
24											
25	Total Transportation Service	48,302.2		71,171		70,799		3,760	2,131		74,931
26											
27	Total Non-Bypass Sales & Transportation Service	160,759.9		$ 1,204,417		$ 545,514		$ 28,970	852,920		$ 1,233,387
28											
29	Cross Reference	- Sect 7-TAB 7.1, Schedule 8		- Sect 7-TAB 7.1, Schedule 11				- Sect 7-TAB 7.1, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Increase / (Decrease) 5.31% $/GJ	Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ------ Revised Rates ------- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,210.8	$ 0.142	$ 885	$ 0.134	$ 834	$ -	$ -	6	$ 0.142	$ 885
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	230.7	0.238	55	0.217	50	-	-	1	0.238	55
6	Burrard Thermal - Firm	1,372.0	7.286	9,996	7.276	9,983	-	-	1	7.286	9,996
7	FEVI - Firm	36,847.2	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
9	Schedule 25 - Firm Service	1,295.0	0.608	788	0.601	778	-	-	7	0.608	788
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	45,955.7		11,724		11,645		-	17		11,724
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	206,715.6		$ 1,216,141		$ 557,159		$ 28,970	852,937		$ 1,245,111
15											
16	Cross Reference	- Sect 7-TAB 7.1, Schedule 8		- Sect 7-TAB 7.1, Schedule 11				- Sect 7-TAB 7.1, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Effective Increase / (Decrease) 12.02% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ------ Revised Rates ------- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,816.4	$ 10.718	$ 750,275	$ 4.822	$ 337,585	$ 0.580	$ 40,571	776,109	$ 11.298	$ 790,846
4	Schedule 2 - Small Commercial	23,331.9	9.470	222,969	3.606	84,913	0.433	10,205	76,135	9.903	233,174
5	Schedule 3 - Large Commercial	16,514.8	8.464	139,001	2.811	46,161	0.338	5,547	4,977	8.802	144,548
6	Schedules 1, 2 and 3	109,663.1		1,112,245		468,659		56,323	857,221		1,168,568
7											
8	Schedule 4 - Seasonal	185.2	6.820	1,263	1.501	278	0.184	34	18	7.004	1,297
9	Schedule 5 - General Firm	2,407.7	7.859	18,921	2.529	6,089	0.304	732	236	8.163	19,653
10											
11	Industrials										
12	Schedule 7 - Interruptible	14.2	11.368	133	4.872	57	0.598	7	4	11.966	140
13											
14	Schedule 6 - N G V Fuel - Stations	56.4	8.865	500	3.918	221	0.479	27	21	9.344	527
15											
16	Total Sales	112,326.6		1,133,062		475,304		57,123	857,500		1,190,185
17											
18	TRANSPORTATION SERVICE										
19	Schedule 22 - Firm Service	11,020.6	0.758	7,953	0.739	7,758	0.089	932	14	0.847	8,885
20	- Interruptible Service	12,302.6	0.906	11,100	0.902	11,055	0.108	1,329	21	1.014	12,429
21	Schedule 23 - Large Commercial	7,485.3	3.101	21,153	3.095	21,114	0.372	2,537	1,505	3.473	23,690
22	Schedule 25 - Firm Service	12,171.2	2.040	24,625	2.034	24,556	0.244	2,951	550	2.284	27,576
23	Schedule 27 - Interruptible Service	5,804.8	1.240	7,390	1.235	7,362	0.148	884	101	1.388	8,274
24											
25	Total Transportation Service	48,784.5		72,221		71,845		8,633	2,191		80,854
26											
27	Total Non-Bypass Sales & Transportation Service	161,111.1		$ 1,205,283		$ 547,149		$ 65,756	859,691		$ 1,271,039
28											
29	Cross Reference	- Sect 7-TAB 7.1, Schedule 9		- Sect 7-TAB 7.1, Schedule 12				- Sect 7-TAB 7.1, Schedule 3			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 12.02% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,068.9	$ 0.146	$ 885	$ 0.138	$ 836	$ -	$ -	6	$ 0.146	$ 885
4	- Interruptible Service	-	-	-	-	-	-	-	1	$ -	-
5	Byron Creek (aka Fording Coal Mountain)	227.4	0.242	55	0.220	50	-	-	1	$ 0.242	55
6	Burrard Thermal - Firm	1,372.0	7.286	9,996	7.276	9,983	-	-	1	$ 7.286	9,996
7	FEVI - Firm	37,080.0	-	-	-	-	-	-	1	$ -	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	$ -	-
9	Schedule 25 - Firm Service	1,300.1	0.606	788	0.598	778	-	-	7	$ 0.606	788
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	46,048.4		11,724		11,647		-	17		11,724
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	207,159.5		$ 1,217,007		$ 558,796		$ 65,756	859,708		$ 1,282,763
15											
16	Cross Reference	- Sect 7-TAB 7.1, Schedule 9		- Sect 7-TAB 7.1, Schedule 12				- Sect 7-TAB 7.1, Schedule 3			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 2,526	$ 3,020	$ 2,335	$ (685)	- Sect 7-TAB 7.1, Schedule 76
4						
5	Connection Charge	2,690	2,907	2,640	(267)	- Sect 7-TAB 7.1, Schedule 76
6						
7	NSF Returned Cheque Charges	69	82	79	(3)	- Sect 7-TAB 7.1, Schedule 76
8						
9	Other Recoveries	210	76	122	46	- Sect 7-TAB 7.1, Schedule 76
10						
11	Total Other Utility Revenue	5,495	6,085	5,176	(909)	
12						
13	**Miscellaneous Revenue**					
14						
15	FEVI Wheeling Charge	3,353	3,455	3,455	0	
16						
17	SCP Third Party Revenue	12,850	14,798	14,827	29	
18						
19	FEVI SAP Lease Income	130	56	56	-	- Sect 7-TAB 7.1, Schedule 76
20						
21	Biomethane Other Revenue	-	-	(82)	(82)	- Sect 7-TAB 7.1, Schedule 76
22						
23	CNG & LNG Service Revenues	-	-	-	-	- Sect 7-TAB 7.1, Schedule 76
24						
25						
26	Total Miscellaneous	16,333	18,309	18,256	(53)	
27						
28	**Total Other Operating Revenue**	$ 21,828	$ 24,394	$ 23,432	$ (962)	- Sect 7-TAB 7.1, Schedule 4

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,335	$ 2,333	$ (2)	- Sect 7-TAB 7.1, Schedule 76
4					
5	Connection Charge	2,640	2,662	22	- Sect 7-TAB 7.1, Schedule 76
6					
7	NSF Returned Cheque Charges	79	79	-	- Sect 7-TAB 7.1, Schedule 76
8					
9	Other Recoveries	122	122	-	- Sect 7-TAB 7.1, Schedule 76
10					
11	Total Other Utility Revenue	5,176	5,196	20	
12					
13	**Miscellaneous Revenue**				
14					
15	FEVI Wheeling Charge	3,455	3,456	1	- Sect 7-TAB 7.1, Schedule 2
16					
17	SCP Third Party Revenue	14,827	14,852	25	- Sect 7-TAB 7.1, Schedule 2
18					
19	FEVI SAP Lease Income	56	17	(39)	- Sect 7-TAB 7.1, Schedule 76
20					
21	Biomethane Other Revenue	(82)	(62)	20	- Sect 7-TAB 7.1, Schedule 76
22					
23	CNG & LNG Service Revenues	-	3,744	3,744	- Sect 7-TAB 7.1, Schedule 76
24					
25					
26	Total Miscellaneous	18,256	22,007	3,751	
27					
28	**Total Other Operating Revenue**	$ 23,432	$ 27,203	$ 3,771	- Sect 7-TAB 7.1, Schedule 5

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
3	Late Payment Charge	$ 2,333	$ 2,333	$0	- Sect 7-TAB 7.1, Schedule 76
5	Connection Charge	2,662	2,685	23	- Sect 7-TAB 7.1, Schedule 76
7	NSF Returned Cheque Charges	79	79	-	- Sect 7-TAB 7.1, Schedule 76
9	Other Recoveries	122	126	4	- Sect 7-TAB 7.1, Schedule 76
11	Total Other Utility Revenue	5,196	5,223	27	
13	**Miscellaneous Revenue**				
15	FEVI Wheeling Charge	3,456	3,464	8	- Sect 7-TAB 7.1, Schedule 3
17	SCP Third Party Revenue	14,852	14,827	(25)	- Sect 7-TAB 7.1, Schedule 3
19	FEVI SAP Lease Income	17	-	(17)	- Sect 7-TAB 7.1, Schedule 76
21	Biomethane Other Revenue	(62)	(29)	33	- Sect 7-TAB 7.1, Schedule 76
23	CNG & LNG Service Revenues	3,744	5,398	1,654	- Sect 7-TAB 7.1, Schedule 76
26	Total Miscellaneous	22,007	23,660	1,653	
28	**Total Other Operating Revenue**	$ 27,203	$ 28,883	$ 1,680	- Sect 7-TAB 7.1, Schedule 6

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TAB 7.1
Schedule 21

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 43,296	$ 48,663	$ 48,125	$ 55,081	$ 57,205	
2	COPE Costs	28,413	31,938	31,054	35,953	37,944	
3	COPE Customer Services Costs	-	-	-	11,788	11,144	
4	IBEW Costs	22,625	26,559	25,532	26,867	28,234	
5							
6	**Labour Costs**	**94,334**	**107,160**	**104,712**	**129,689**	**134,526**	
7							
8	Vehicle Costs	3,625	3,084	3,280	3,632	3,685	
9	Employee Expenses	5,805	5,227	4,035	5,553	5,716	
10	Materials and Supplies	6,738	7,191	5,494	6,981	7,347	
11	Computer Costs	10,214	11,991	10,856	14,489	15,077	
12	Fees and Administration Costs *	29,309	28,512	27,858	59,202	64,499	
13	Contractor Costs *	62,151	60,052	61,910	16,129	17,873	
14	Facilities	13,023	14,318	12,984	15,827	14,573	
15	Recoveries & Revenue	(18,680)	(22,854)	(17,094)	(27,383)	(26,824)	
16							
17	**Non-Labour Costs**	**112,185**	**107,520**	**109,323**	**94,430**	**101,945**	
18							
19							
20	**Total Gross O&M Expenses**	**206,519**	**214,680**	**214,035**	**224,119**	**236,472**	
21							
22	Add: PST Savings	-	-	645	(0)	(0)	
23	Less: Capitalized Overhead	(28,905)	(30,055)	(30,055)	(31,377)	(33,106)	
24							- Sect 7-TAB 7.1, Schedule 4
25	**Total O&M Expenses**	**$ 177,614**	**$ 184,625**	**$ 184,625**	**$ 192,742**	**$ 203,365**	- Sect 7-TAB 7.1, Schedule 5
26	* Note: 2012 & 2013 reflect customer service costs previously contracted						- Sect 7-TAB 7.1, Schedule 6

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 9,763	$ 10,609	$ 9,072	$ 11,068	$ 11,519	
2								
3	Operation Centre - Distribution	100-21	10,552	10,451	10,720	12,107	12,781	
4	Asset Management - Distribution	100-22	1,747	2,437	2,286	3,242	4,569	
5	Preventative Maintenance - Distribution	100-23	2,105	2,377	2,433	2,980	3,232	
6	Distribution Operations - General	100-24	5,609	5,512	5,800	5,607	5,904	
7	Meter Exchange	100-25	-	-	-	-	-	
8	Emergency Management	100-26	4,528	5,488	5,269	4,930	5,077	
9	Distribution Operations Total	100-20	24,541	26,266	26,508	28,865	31,563	
10								
11	Distribution Corrective - Meters	100-31	1,763	1,524	1,602	1,548	1,594	
12	Distribution Corrective - Propane	100-32	-	5	5	-	-	
13	Distribution Corrective - Leak Repair	100-33	1,331	996	1,135	1,245	1,282	
14	Distribution Corrective - Stations	100-34	622	727	648	751	770	
15	Distribution Corrective - General	100-35	393	534	353	505	520	
16	Distribution Maintenance Total	100-30	4,109	3,785	3,742	4,049	4,167	
17								
18	**Distribution Total**	**100**	**38,413**	**40,660**	**39,323**	**43,982**	**47,250**	
19								
20	Transmission Supervision	200-11	3,205	3,161	3,880	4,855	5,790	
21								
22	Pipeline Operation	200-21	2,135	2,836	1,650	2,720	2,762	
23	Right of Way	200-22	1,592	1,345	362	494	537	
24	Compression	200-23	1,981	1,922	915	1,020	1,048	
25	Gas Control	200-24	2,611	3,105	3,132	2,848	3,000	
26	Transmission Pipeline Integrity Project (TPIP)	200-25	2,722	3,317	3,240	2,611	2,797	
27	Transmission Operations Total	200-20	11,041	12,525	9,298	9,694	10,143	
28								
29	Pipeline - Maintenance	200-31	220	194	1,961	2,321	2,150	
30	Compression - Maintenance	200-32	242	172	1,219	1,251	1,381	
31	TPIP - Maintenance	200-33	869	929	954	541	557	
32	Transmission Maintenance Total	200-30	1,331	1,295	4,135	4,113	4,088	
33								
34	**Transmission Total**	**200**	**15,577**	**16,980**	**17,313**	**18,662**	**20,021**	
35								
36	LNG Plant Operations	300-11	930	1,088	977	1,122	1,199	
37	LNG Plant Maintenance	300-21	431	277	381	440	474	
38								
39	**LNG Plant Total**	**300**	**1,361**	**1,365**	**1,357**	**1,562**	**1,673**	
40								
41	Measurement Operations	400-11	4,125	4,297	4,233	4,930	5,239	
42	Measurement Maintenance	400-21	1,740	2,334	2,222	2,180	2,231	
43								
44	**Measurement Total**	**400**	**5,865**	**6,630**	**6,455**	**7,110**	**7,470**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Facilities Management	500-10	$ 6,506	$ 5,968	$ 5,891	$ 8,970	$ 8,912	
2	Shops & Stores	500-20	4,016	4,152	3,907	4,677	4,783	
3	Operations Engineering	500-30	8,317	8,679	9,004	10,307	10,781	
4	Property Services	500-40	1,204	1,307	1,283	1,411	1,453	
5	System Integrity	500-50	2,330	2,492	2,564	2,358	2,399	
6	Environmental Health & Safety	500-60	2,365	2,504	2,404	2,893	3,057	
7	Operations Governance	500-70	1,660	1,800	1,899	1,649	1,705	
8	**General Operations Total**	**500**	**26,398**	**26,903**	**26,953**	**32,265**	**33,090**	
9								
10	Energy Efficiency	600-10	(7)	-	(0)	0	(0)	
11	Marketing - Supervision	600-20	780	634	(825)	(807)	(785)	
12	Corporate & Marketing Communications	600-30	3,133	3,673	2,911	3,800	4,017	
13	Marketing Planning & Development	600-40	626	669	531	955	981	
14	**Marketing Total**	**600**	**4,532**	**4,976**	**2,618**	**3,948**	**4,212**	
15								
16	Customer Care - Supervision	700-10	1,504	2,126	2,205	2,793	2,883	
17	Customer Contact	700-20	47,961	49,422	49,049	40,112	43,247	
18	Bad Debt Management and Administration	700-30	3,384	6,018	5,612	5,227	5,268	
19	Customer Management & Sales	700-40	5,645	4,176	5,886	6,989	7,309	
20	**Customer Care Total**	**700**	**58,494**	**61,742**	**62,752**	**55,121**	**58,706**	
21								
22	Business & IT Services - Supervision	800-10	999	1,268	1,194	0	-	
23	Application Management	800-20	10,942	13,512	12,467	16,118	16,871	
24	Infrastructure Management	800-30	6,026	6,775	7,108	8,760	9,154	
25	Procurement Services	800-40	821	874	864	1,265	1,412	
26	**Business & IT Services Total**	**800**	**18,788**	**22,428**	**21,633**	**26,142**	**27,437**	
27								
28	Administration & General	900-11	5,608	(1,185)	2,432	2,054	2,576	
29	Insurance	900-12	4,410	4,631	4,631	4,397	4,167	
30	Finance and Regulatory Affairs	900-13	9,110	9,994	9,952	11,071	11,399	
31	Shared Services Agreement	900-14	742	1,899	325	(449)	(87)	
32	Corporate Administration Total	900-10	19,870	15,339	17,340	17,073	18,054	
33	Forecasting	900-20	1,721	1,672	1,696	3,036	3,335	
34	Public Affairs	900-30	1,616	1,762	1,730	1,796	1,850	
35	Business Development	900-40	2,013	3,183	3,808	3,979	4,113	
36	Human Resources	900-50	6,551	6,930	6,947	8,152	8,457	
37	Other Post Employment Benefits (OPEB)	900-60	5,320	4,111	4,111	1,290	801	
38	**Administration & General Total**	**900**	**37,091**	**32,996**	**35,632**	**35,325**	**36,611**	
39								
40	**Total Gross O&M Expenses**		**206,519**	**214,680**	**214,035**	**224,119**	**236,471**	
41								
42	Add: PST Savings		-	-	645	(0)	(0)	
43	Less: Capitalized Overhead		(28,905)	(30,055)	(30,055)	(31,377)	(33,106)	
44								- Sect 7-TAB 7.1, Schedule 4
45	**Total O&M Expenses**		**$ 177,614**	**$ 184,625**	**$ 184,625**	**$ 192,742**	**$ 203,365**	- Sect 7-TAB 7.1, Schedule 5
46								- Sect 7-TAB 7.1, Schedule 6

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Total Expenses	2011 PROJECTED Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (4) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 16,054	$ 16,067	$ 15,174	$ 15,174	$ (893)	
4							
5	General, School and Other	32,591	34,144	33,684	33,684	(460)	
6							
7		48,645	50,211	48,858	48,858	(1,353)	
8							
9	Add / Less: Deferred Property Taxes	548	-	1,353	1,353	1,353	
10							
11	Total	$ 49,193	$ 50,211	$ 50,211	$ 50,211	$ -	- Sect 7-TAB 7.1, Schedule 4

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Total Expenses	2012 Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 15,174	$ 13,728	$ 13,728	$ (1,446)	
4						
5	General, School and Other	33,684	35,928	35,928	2,244	
6						
7		48,858	49,656	49,656	798	
8						
9	Add / Less: Deferred Property Taxes	1,353	-	-	(1,353)	
10						
11	Total	$ 50,211	$ 49,656	$ 49,656	$ (555)	- Sect 7-TAB 7.1, Schedule 5

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Total Expenses	2013 Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 13,728	$ 13,728	$ 13,728	$ -	
4						
5	General, School and Other	35,928	37,511	37,511	1,583	
6						
7		49,656	51,239	51,239	1,583	
8						
9	Add / Less: Deferred Property Taxes	-	-	-	-	
10						
11	Total	$ 49,656	$ 51,239	$ 51,239	$ 1,583	- Sect 7-TAB 7.1, Schedule 6

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 98,124	$ 100,534	$ 99,576	$ (958)	- Sect 7-TAB 7.1, Schedule 54
4						
5	Less: Amortization of Contributions in Aid of Construction	(6,432)	(6,677)	(5,484)	1,193	- Sect 7-TAB 7.1, Schedule 63
6		91,692	93,857	94,092	235	
7						
8	Add: Removal Cost Provision	8,038	11,290	11,290	-	
9		99,730	105,147	105,382	235	- Sect 7-TAB 7.1, Schedule 33
10						
11	**Amortization Expense**					
12						
13	Amortization of Deferred Charges	$ (2,572)	$ (5,269)	$ (5,271)	$ (2)	- Sect 7-TAB 7.1, Schedule 67
14						
15	TOTAL	$ 97,158	$ 99,878	$ 100,111	$ 233	- Sect 7-TAB 7.1, Schedule 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 99,576	$ 118,071	$ 18,495	- Sect 7-TAB 7.1, Schedule 57
4					
5	Less: Amortization of Contributions in Aid of Construction	(5,484)	(6,277)	(793)	- Sect 7-TAB 7.1, Schedule 64
6		94,092	111,794	17,702	
7					
8	Add: Removal Cost Provision	11,290	16,198	4,908	- Sect 7-TAB 7.1, Schedule 5
9		105,382	127,992	22,610	- Sect 7-TAB 7.1, Schedule 34
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ (5,271)	$ 5,928	$ 11,199	- Sect 7-TAB 7.1, Schedule 69
14					
15	TOTAL	$ 100,111	$ 133,920	$ 33,809	- Sect 7-TAB 7.1, Schedule 5

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 118,071	$ 123,524	$ 5,453	- Sect 7-TAB 7.1, Schedule 60
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,277)	(6,219)	58	- Sect 7-TAB 7.1, Schedule 65
6		111,794	117,305	5,511	
7					
8	Add: Removal Cost Provision	16,198	16,743	545	- Sect 7-TAB 7.1, Schedule 6
9		127,992	134,048	5,511	- Sect 7-TAB 7.1, Schedule 35
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ 5,928	$ 18,187	$ 12,259	- Sect 7-TAB 7.1, Schedule 71
14					
15	TOTAL	$ 133,920	$ 152,235	$ 17,770	- Sect 7-TAB 7.1, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing Rates	------ Revised Rates ------- Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 198,447	$ 208,413	$ 207,377	$ -	$ 207,377	$ (1,036)	- Sect 7-TAB 7.1, Schedule 4
3	Deduct - Interest on Debt	(103,862)	(108,504)	(105,981)	-	(105,981)	2,523	- Sect 7-TAB 7.1, Schedule 79
4	Net Additions (Deductions)	(10,829)	(9,722)	(14,485)	-	(14,485)	(4,763)	- Sect 7-TAB 7.1, Schedule 33
5	Accounting Income After Tax	83,756	90,187	86,911	-	86,911	(3,276)	
6	Taxable Income Adj - SCP Landscaping Deduction	(7,834)	-		-	-	-	
7	Taxable Income Adj - Tax on SCP Landscaping	2,233	-		-	-	-	
8	Adjusted Taxable Income After Tax	$ 78,155	$ 90,187	$ 86,911	$ -	$ 86,911	$ (3,276)	
9								
10	Current Income Tax Rate	28.50%	26.50%	26.50%	26.50%	26.50%	0.00%	
11	1 - Current Income Tax Rate	71.50%	73.50%	73.50%	73.50%	73.50%	0.00%	
12								
13	Taxable Income	$ 109,307	$ 122,703	$ 118,246	$ -	$ 118,246	$ (4,457)	
14								
15								
16	Income Tax - Current	$ 31,152	$ 32,516	$ 31,335	$ -	$ 31,335	$ (1,181)	
17								
18	**Total Income Tax**	$ 31,152	$ 32,516	$ 31,335	$ -	$ 31,335	$ (1,181)	- Sect 7-TAB 7.1, Schedule 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing Rates	2012 Revised Rates Revised Revenue	2012 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 207,377	$ 190,451	$ 21,728	$ 212,179	$ 4,802	- Sect 7-TAB 7.1, Schedule 5
3	Deduct - Interest on Debt	(105,981)	(108,191)	(1)	(108,192)	(2,211)	- Sect 7-TAB 7.1, Schedule 80
4	Net Additions (Deductions)	(14,485)	(30,553)	-	(30,553)	(16,068)	- Sect 7-TAB 7.1, Schedule 34
5	Accounting Income After Tax	86,911	51,707	21,727	73,434	(13,477)	
6	Taxable Income Adj - SCP Landscaping Deduction	-	-	-	-	-	
7	Taxable Income Adj - Tax on SCP Landscaping	-	-	-	-	-	
8	Adjusted Taxable Income After Tax	$ 86,911	$ 51,707	$ 21,727	$ 73,434	$ (13,477)	
9							
10	Current Income Tax Rate	26.50%	25.00%	25.00%	25.00%	-1.50%	
11	1 - Current Income Tax Rate	73.50%	75.00%	75.00%	75.00%	1.50%	
12							
13	Taxable Income	$ 118,246	$ 68,943	$ 28,969	$ 97,912	$ (20,334)	
14							
15							
16	Income Tax - Current	$ 31,335	$ 17,236	$ 7,242	$ 24,478	$ (6,857)	
17							
18	**Total Income Tax**	$ 31,335	$ 17,236	$ 7,242	$ 24,478	$ (6,857)	- Sect 7-TAB 7.1, Schedule 5

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing Rates	2013 Revised Rates: Revised Revenue	2013 Revised Rates: Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 212,179	$ 166,760	$ 49,319	$ 216,079	$ 3,900	- Sect 7-TAB 7.1, Schedule 6
3	Deduct - Interest on Debt	(108,192)	(110,113)	(10)	(110,123)	(1,931)	- Sect 7-TAB 7.1, Schedule 81
4	Net Additions (Deductions)	(30,553)	(15,476)	-	(15,476)	15,077	- Sect 7-TAB 7.1, Schedule 35
5	Accounting Income After Tax	73,434	41,171	49,309	90,480	17,046	
6	Taxable Income Adj - SCP Landscaping Deduction	-		-	-	-	
7	Taxable Income Adj - Tax on SCP Landscaping	-		-	-	-	
8	Adjusted Taxable Income After Tax	$ 73,434	$ 41,171	$ 49,309	$ 90,480	$ 17,046	
9							
10	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
11	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
12							
13	Taxable Income	$ 97,912	$ 54,895	$ 65,745	$ 120,640	$ 22,728	
14							
15							
16	Income Tax - Current	$ 24,478	$ 13,724	$ 16,436	$ 30,160	$ 5,682	
17							
18	**Total Income Tax**	$ 24,478	$ 13,724	$ 16,436	$ 30,160	$ 5,682	- Sect 7-TAB 7.1, Schedule 6

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 670	$ 500	$ 700	$ 200	
3	Depreciation	99,730	105,147	105,382	235	- Sect 7-TAB 7.1, Schedule 27
4	Amortization of Debt Issue Expenses	575	621	527	(94)	
5	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,597	2,029	1,852	(177)	
6	Pension Expense	4,779	5,704	5,704	-	
7	OPEB Expense	5,320	5,297	5,297	-	
8						
9	**Deductions:**					
10	Amortization of Deferred Charges	(2,572)	(5,269)	(5,271)	(2)	- Sect 7-TAB 7.1, Schedule 27
11	Capital Cost Allowance	(91,846)	(97,259)	(96,930)	329	- Sect 7-TAB 7.1, Schedule 36
12	Cumulative Eligible Capital Allowance	(1,020)	(937)	(966)	(29)	
13	Debt Issue Costs	(1,067)	(803)	(1,060)	(257)	
14	Vehicle Lease Payment	(3,141)	(3,736)	(3,462)	274	
15	Pension Contributions	(9,359)	(7,322)	(10,801)	(3,479)	
16	OPEB Contributions	(1,382)	(503)	(2,032)	(1,529)	
17	Overheads Capitalized Expensed for Tax Purposes	(12,396)	(12,881)	(12,881)	-	
18	Removal Costs	-	-	-	-	
19	Major Inspection Costs	(763)	(310)	(626)	(316)	
20	Taxable Capital Gain	46	-	-	-	
21	Biomethane Other Revenue	-	-	82	82	
22						
23	TOTAL	$ (10,829)	$ (9,722)	$ (14,485)	$ (4,763)	- Sect 7-TAB 7.1, Schedule 30

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	700	$ -	
3	Depreciation	105,382	127,992	22,610	- Sect 7-TAB 7.1, Schedule 28
4	Amortization of Debt Issue Expenses	527	596	69	
5	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,852	2,056	204	
6	Pension Expense	5,704	8,401	2,697	
7	OPEB Expense	5,297	4,134	(1,163)	
8					
9	**Deductions:**				
10	Amortization of Deferred Charges	(5,271)	5,928	11,199	- Sect 7-TAB 7.1, Schedule 28
11	Capital Cost Allowance	(96,930)	(133,697)	(36,767)	- Sect 7-TAB 7.1, Schedule 37
12	Cumulative Eligible Capital Allowance	(966)	(898)	68	
13	Debt Issue Costs	(1,060)	(863)	197	
14	Vehicle Lease Payment	(3,462)	(3,776)	(314)	
15	Pension Contributions	(10,801)	(11,340)	(539)	
16	OPEB Contributions	(2,032)	(2,261)	(229)	
17	Overheads Capitalized Expensed for Tax Purposes	(12,881)	(13,447)	(566)	
18	Removal Costs	-	(12,609)	(12,609)	
19	Major Inspection Costs	(626)	(1,531)	(905)	
20	Taxable Capital Gain	-	-	-	
21	Biomethane Other Revenue	82	62	(20)	
22					
23	TOTAL	$ (14,485)	$ (30,553)	$ (16,068)	- Sect 7-TAB 7.1, Schedule 31

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	700	$ -	
3	Depreciation	127,992	134,048	6,056	- Sect 7-TAB 7.1, Schedule 29
4	Amortization of Debt Issue Expenses	596	621	25	
5	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,056	2,190	134	
6	Pension Expense	8,401	8,062	(339)	
7	OPEB Expense	4,134	4,367	233	
8					
9	**Deductions:**				
10	Amortization of Deferred Charges	5,928	18,187	12,259	- Sect 7-TAB 7.1, Schedule 29
11	Capital Cost Allowance	(133,697)	(136,030)	(2,333)	- Sect 7-TAB 7.1, Schedule 38
12	Cumulative Eligible Capital Allowance	(898)	(855)	43	
13	Debt Issue Costs	(863)	(411)	452	
14	Vehicle Lease Payment	(3,776)	(4,006)	(230)	
15	Pension Contributions	(11,340)	(11,542)	(202)	
16	OPEB Contributions	(2,261)	(2,374)	(113)	
17	Overheads Capitalized Expensed for Tax Purposes	(13,447)	(14,188)	(741)	
18	Removal Costs	(12,609)	(12,932)	(323)	
19	Major Inspection Costs	(1,531)	(1,342)	189	
20	Taxable Capital Gain	-	-	-	
21	Biomethane Other Revenue	62	29	(33)	
22					
23	TOTAL	$ (30,553)	$ (15,476)	$ 15,077	- Sect 7-TAB 7.1, Schedule 32

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate	UCC Balance 12/31/2010	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,128,841	$ -	$ -	$ (45,154)	$ 1,083,687
2	1(b)	6%	12,644	-	2,985	(848)	14,781
3	2	6%	154,315	-	-	(9,259)	145,056
4	3	5%	2,685	-	-	(134)	2,551
5	6	10%	185	-	-	(19)	166
6	7	15%	4,025	-	1,519	(718)	4,826
7	8	20%	19,113	-	7,425	(4,565)	21,973
8	10	30%	1,816	-	232	(580)	1,468
9	12	100%	2,836	-	13,293	(9,482)	6,647
10	13	manual	1,793	-	100	(1,727)	166
11	14	manual	-	-	-	-	-
12	17	8%	206	-	-	(16)	190
13	38	30%	429	-	161	(153)	437
14	39	25%	-	-	-	-	-
15	45	45%	666	-	-	(300)	366
16	47	8%	5,947	-	2,497	(576)	7,868
17	49	8%	40,535	-	48,214	(5,171)	83,578
18	50 / 52	55% / 100%	656	-	6,400	(2,249)	4,807
19	51	6%	226,247	-	64,001	(15,495)	274,753
20	43.2	50%	-	-	1,934	(484)	1,450
21							
22		Total	$ 1,602,939	$ -	$ 148,761	$ (96,930)	$ 1,654,770
23							
24	Cross Reference					- Sect 7-TAB 7.1, Schedule 33	
25							

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	UCC Balance 12/31/2011	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,083,687	$ -	$ 60	$ (43,349)	$ 1,040,398
2	1(b)	6%	14,781	-	13,512	(1,292)	27,001
3	2	6%	145,056	1	-	(8,703)	136,354
4	3	5%	2,551	-	-	(128)	2,423
5	6	10%	166	1	-	(17)	150
6	7	15%	4,826	-	4,805	(1,084)	8,547
7	8	20%	21,973	-	11,902	(5,585)	28,290
8	10	30%	1,468	1	465	(510)	1,424
9	12	100%	6,647	(1)	59,188	(36,240)	29,594
10	13	manual	166	-	3,026	(2,961)	231
11	14	manual	-	-	-	-	-
12	17	8%	190	-	-	(15)	175
13	38	30%	437	-	200	(161)	476
14	39	25%	-	-	-	-	-
15	45	45%	366	-	-	(165)	201
16	47	8%	7,868	1	2,450	(728)	9,591
17	49	8%	83,578	-	21,586	(7,550)	97,614
18	50	55%	4,807	-	10,236	(5,459)	9,584
19	51	6%	274,753	-	67,474	(18,509)	323,718
20	43.2	50%	1,450	1	2,063	(1,241)	2,273
21							
22		Total	$ 1,654,770	$ 4	$ 196,967	$ (133,697)	$ 1,718,044
23							
24	Cross Reference					- Sect 7-TAB 7.1, Schedule 34	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	UCC Balance 12/31/2012	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,040,398	$ -	$ -	$ (41,616)	$ 998,782
2	1(b)	6%	27,001	-	3,187	(1,716)	28,472
3	2	6%	136,354	(1)	-	(8,181)	128,172
4	3	5%	2,423	-	-	(121)	2,302
5	6	10%	150	-	-	(15)	135
6	7	15%	8,547	-	4,051	(1,586)	11,012
7	8	20%	28,290	-	7,349	(6,393)	29,246
8	10	30%	1,424	(1)	155	(450)	1,128
9	12	100%	29,594	-	10,800	(34,994)	5,400
10	13	manual	231	-	100	(331)	-
11	14	manual	-	-	-	-	-
12	17	8%	175	(1)	-	(14)	160
13	38	30%	476	-	200	(173)	503
14	39	25%	-	-	-	-	-
15	45	45%	201	1	-	(91)	111
16	47	8%	9,591	-	541	(789)	9,343
17	49	8%	97,614	-	16,243	(8,459)	105,398
18	50	55%	9,584	-	7,200	(7,251)	9,533
19	51	6%	323,718	-	88,321	(22,073)	389,966
20	43.2	50%	2,273	(1)	2,563	(1,777)	3,058
21							
22		Total	$ 1,718,044	$ (3)	$ 140,710	$ (136,030)	$ 1,722,721
23							
24	Cross Reference					- Sect 7-TAB 7.1, Schedule 35	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Adjustments	2011 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	Gas Plant in Service, Beginning	$ 3,302,151	$ 3,453,394	$ 3,388,861	$ -	$ 3,388,861	$ (64,533)	- Sect 7-TAB 7.1, Schedule 45
2	Opening Balance Adjustment	-	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,388,862	3,538,378	3,542,280	-	3,542,280	3,902	- Sect 7-TAB 7.1, Schedule 45
4								
5	Accumulated Depreciation Beginning - Plant	$ (779,846)	$ (835,365)	$ (847,526)	$ -	$ (847,526)	$ (12,161)	- Sect 7-TAB 7.1, Schedule 54
6	Opening Balance Adjustment	-	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(847,526)	(885,651)	(923,722)	-	(923,722)	(38,071)	- Sect 7-TAB 7.1, Schedule 54
8								
9	Negative Salvage Beginning - Plant	$ -	$ -	$ -	$ -	$ -	$ -	
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	Negative Salvage Ending - Plant	-	-	-	-	-	-	
12								
13	CIAC, Beginning	$ (163,384)	$ (183,885)	$ (164,148)	$ -	$ (164,148)	$ 19,737	- Sect 7-TAB 7.1, Schedule 63
14	Opening Balance Adjustment	-	-	-	-	-	-	
15	CIAC, Ending	(164,149)	(194,753)	(171,372)	-	(171,372)	23,381	- Sect 7-TAB 7.1, Schedule 63
16								
17	Accumulated Amortization Beginning - CIAC	$ 44,266	$ 47,062	$ 46,752	$ -	$ 46,752	$ (310)	- Sect 7-TAB 7.1, Schedule 63
18	Opening Balance Adjustment	-	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	46,752	50,245	48,742	-	48,742	(1,503)	- Sect 7-TAB 7.1, Schedule 63
20								
21	Net Plant in Service, Mid-Year	$ 2,413,563	$ 2,494,713	$ 2,459,934	$ -	$ 2,459,934	$ (34,779)	
22								
23 *	Adjustment to 13-Month Average	(2,157)	-	(11,675)	-	(11,675)	(11,675)	
24	Work in Progress, No AFUDC	18,823	15,627	17,110	-	17,110	1,483	
25	Unamortized Deferred Charges	(33,398)	6,770	(27,664)	-	(27,664)	(34,434)	- Sect 7-TAB 7.1, Schedule 67
26	Cash Working Capital	(5,226)	(6,534)	(3,635)	-	(3,635)	2,899	- Sect 7-TAB 7.1, Schedule 72
27	Other Working Capital	135,255	120,091	103,157	-	103,157	(16,934)	- Sect 7-TAB 7.1, Schedule 72
28	Future Income Taxes Regulatory Asset	266,200	292,155	261,151	-	261,151	(31,004)	- Sect 7-TAB 7.1, Schedule 78
29	Future Income Taxes Regulatory Liability	(266,200)	(292,155)	(261,151)	-	(261,151)	31,004	- Sect 7-TAB 7.1, Schedule 78
30	LILO Benefit	(1,648)	(1,482)	(1,482)	-	(1,482)	-	
31	**Utility Rate Base**	$ 2,525,213	$ 2,629,185	$ 2,535,745	$ -	$ 2,535,745	$ (93,440)	- Sect 7-TAB 7.1, Schedule 79
32								
33 *	Note FEI: Oct 2011 In-Service date applied to Kootenay River Crossing & Fraser River Crossing							

FORTISBC ENERGY INC. - Mainland

May 4, 2011

Section 7
TAB 7.1
Schedule 40

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Forecast Existing 2011 Rates	2012 Forecast Adjustments	2012 Forecast Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,388,861	$ 3,542,280	$ -	$ 3,542,280	$ 153,419	- Sect 7-TAB 7.1, Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,542,280	3,770,188	-	3,770,188	227,908	- Sect 7-TAB 7.1, Schedule 48
4							
5	Accumulated Depreciation Beginning - Plant	$ (847,526)	$ (923,722)	$ -	$ (923,722)	$ (76,196)	- Sect 7-TAB 7.1, Schedule 57
6	Opening Balance Adjustment (re Negative Salvage)	-	4,405	-	4,405	4,405	- Sect 7-TAB 7.1, Schedule 57
7	Accumulated Depreciation Ending - Plant	(923,722)	(1,014,039)	-	(1,014,039)	(90,317)	- Sect 7-TAB 7.1, Schedule 57
8							
9	Negative Salvage Beginning - Plant	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.1, Schedule 61
10	Opening Balance Adjustment (re Negative Salvage)	-	(4,405)	-	(4,405)	(4,405)	- Sect 7-TAB 7.1, Schedule 61
11	Negative Salvage Ending - Plant	-	(7,994)	-	(7,994)	(7,994)	- Sect 7-TAB 7.1, Schedule 61
12							
9	CIAC, Beginning	$ (164,148)	$ (171,372)	$ -	$ (171,372)	$ (7,224)	- Sect 7-TAB 7.1, Schedule 64
13	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.1, Schedule 64
14	CIAC, Ending	(171,372)	(183,107)	-	(183,107)	(11,735)	- Sect 7-TAB 7.1, Schedule 64
15							
16	Accumulated Amortization Beginning - CIAC	$ 46,752	$ 48,742	$ -	$ 48,742	$ 1,990	- Sect 7-TAB 7.1, Schedule 64
17	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.1, Schedule 64
18	Accumulated Amortization Ending - CIAC	48,742	49,913	-	49,913	1,171	- Sect 7-TAB 7.1, Schedule 64
19							
20	Net Plant in Service, Mid-Year	$ 2,459,934	$ 2,555,445	$ -	$ 2,555,445	$ 95,511	
21							
22 *	Adjustment to 13-Month Average	(11,675)	40,567	-	40,567	52,242	
23	Work in Progress, No AFUDC	17,110	17,110	-	17,110	-	
24	Unamortized Deferred Charges	(27,664)	27,407	-	27,407	55,071	- Sect 7-TAB 7.1, Schedule 69
25	Cash Working Capital	(3,635)	(3,490)	45	(3,445)	190	- Sect 7-TAB 7.1, Schedule 73
26	Other Working Capital	103,157	100,905	-	100,905	(2,252)	- Sect 7-TAB 7.1, Schedule 73
27	Future Income Taxes Regulatory Asset	261,151	271,465	-	271,465	10,314	- Sect 7-TAB 7.1, Schedule 78
28	Future Income Taxes Regulatory Liability	(261,151)	(271,465)	-	(271,465)	(10,314)	- Sect 7-TAB 7.1, Schedule 78
29	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
30	**Utility Rate Base**	$ 2,535,745	$ 2,736,462	$ 45	$ 2,736,507	$ 200,762	- Sect 7-TAB 7.1, Schedule 80
31							
32 *	Note FEI: Jan-12 In-Service date applied to Customer Care Enhancement; Jan-12 Tilbury Land deferral account tsf'd to In-Service						

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Forecast: Existing 2011 Rates	2013 Forecast: Adjustments	2013 Forecast: Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,542,280	$ 3,770,188	$ -	$ 3,770,188	$ 227,908	- Sect 7-TAB 7.1, Schedule 51
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,770,188	3,904,928	-	3,904,928	134,740	- Sect 7-TAB 7.1, Schedule 51
4							
5	Accumulated Depreciation Beginning - Plant	$ (923,722)	$ (1,014,039)	$ -	$ (1,014,039)	$ (90,317)	- Sect 7-TAB 7.1, Schedule 60
6	Opening Balance Adjustment	4,405	-	-	-	(4,405)	
7	Accumulated Depreciation Ending - Plant	(1,014,039)	(1,105,609)	-	(1,105,609)	(91,570)	- Sect 7-TAB 7.1, Schedule 60
8							
9	Negative Salvage Beginning - Plant	$ -	$ (7,994)	$ -	$ (7,994)	$ (7,994)	- Sect 7-TAB 7.1, Schedule 62
10	Opening Balance Adjustment	(4,405)	-	-	-	4,405	
11	Negative Salvage Ending - Plant	(7,994)	(11,805)	-	(11,805)	(3,811)	- Sect 7-TAB 7.1, Schedule 62
12							
9	CIAC, Beginning	$ (171,372)	$ (183,107)	$ -	$ (183,107)	$ (11,735)	- Sect 7-TAB 7.1, Schedule 65
13	Opening Balance Adjustment	-	-	-	-	-	
14	CIAC, Ending	(183,107)	(189,803)	-	(189,803)	(6,696)	- Sect 7-TAB 7.1, Schedule 65
15							
16	Accumulated Amortization Beginning - CIAC	$ 48,742	$ 49,913	$ -	$ 49,913	$ 1,171	- Sect 7-TAB 7.1, Schedule 65
17	Opening Balance Adjustment	-	-	-	-	-	
18	Accumulated Amortization Ending - CIAC	49,913	55,928	-	55,928	6,015	- Sect 7-TAB 7.1, Schedule 65
19							
20	Net Plant in Service, Mid-Year	$ 2,555,445	$ 2,634,300	$ -	$ 2,634,300	$ 78,855	
21							
22	Adjustment to 13-Month Average	40,567	-	-	-	(40,567)	
23	Work in Progress, No AFUDC	17,110	17,110	-	17,110	-	
24	Unamortized Deferred Charges	27,407	38,574	-	38,574	11,167	- Sect 7-TAB 7.1, Schedule 71
25	Cash Working Capital	(3,445)	(2,391)	428	(1,963)	1,482	- Sect 7-TAB 7.1, Schedule 74
26	Other Working Capital	100,905	101,622	-	101,622	717	- Sect 7-TAB 7.1, Schedule 74
27	Future Income Taxes Regulatory Asset	271,465	282,359	-	282,359	10,894	- Sect 7-TAB 7.1, Schedule 78
28	Future Income Taxes Regulatory Liability	(271,465)	(282,359)	-	(282,359)	(10,894)	- Sect 7-TAB 7.1, Schedule 78
29	LILO Benefit	(1,482)	(1,316)	-	(1,316)	166	
30	**Utility Rate Base**	$ 2,736,507	$ 2,787,899	$ 428	$ 2,788,327	$ 51,820	- Sect 7-TAB 7.1, Schedule 81
31							
32							

FORTISBC ENERGY INC. - Mainland May 4, 2011 Section 7
TAB 7.1
Schedule 42

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars (1)	2011 Projected (3)	2012 Forecast (4)	2013 Forecast (5)	Reference (6)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4					
5	Regular Capital Expenditures	$ 94,680	$ 122,471	$ 129,061	
6	Gateway Project	4,500	11,500	1,750	
7					
8	Total Regular Capital Expenditures	$ 99,180	$ 133,971	$ 130,811	
9					
10	Special Projects - CPCN's				
11	Customer Care Enhancement	26,647	13,291	-	
12	Fraser River Xing Seismic Upg	14,149	-	-	
13	Kootenay River Xing	5,864	1,223	-	
14					
15	Total CPCN's	$ 46,660	$ 14,514	$ -	
16					
17					
18	TOTAL CAPITAL EXPENDITURES	$ 145,839	$ 148,485	$ 130,811	
19					
20					
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
22					
23	Regular Capital				
24	Regular Capital Expenditures	$ 99,180	$ 133,971	$ 130,811	
25	Add - Opening WIP	30,007	30,007	30,007	
26	Less - Closing WIP	(30,007)	(30,007)	(30,007)	
27	Capital Vehicle Lease Addition	3,710	3,180	2,860	
28	Add - AFUDC	1,256	1,948	1,769	- Sect 7-TAB 7.1, Schedule 45
29	Add - Overhead Capitalized	30,054	31,375	33,106	- Sect 7-TAB 7.1, Schedule 48
30					- Sect 7-TAB 7.1, Schedule 51
31	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 134,199	$ 170,473	$ 168,546	
32					
33	Special Projects - CPCN's				
34	CPCN Expenditures	46,660	14,514	-	
35	Add - Opening WIP	45,968	53,255	-	
36	Less - Closing WIP	(53,255)	-	-	
37	Add: Projects transferred from Deferral Accounts	-	14,700	-	
38	Less: Adjustments	1	(512)	-	
39	Add - AFUDC	3,988	436	-	- Sect 7-TAB 7.1, Schedule 45
40					- Sect 7-TAB 7.1, Schedule 48
41	TOTAL CPCN ADDITIONS	$ 43,363	$ 82,393	$ -	- Sect 7-TAB 7.1, Schedule 51
42					
43	TOTAL PLANT ADDITIONS	$ 177,562	$ 252,867	$ 168,546	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,043	-	124	-	-	-	-	44,167	44,105
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	-	-	-	-	-	-	1,211	1,211
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	44,918	-	4,800	125	-	(11,301)	1,878	40,420	42,669
17	402-02 Application Software - 20%	10,797	-	4,800	72	-	(91)	1,300	16,878	13,838
18	TOTAL INTANGIBLE	103,447	-	9,724	197	-	(11,392)	3,178	105,154	104,301
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	146	-	-	-	-	-	-	146	146
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	-	-	-	-	-	-	928	928
30	442-00 Structures & Improvements (Tilbury)	4,959	-	-	-	-	-	-	4,959	4,959
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	24,155	-	2,137	66	1,009	(709)	-	26,658	25,407
36	TOTAL MANUFACTURED	47,897	-	2,137	66	1,009	(709)	-	50,400	49,149

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	-	212	-	-	-	-	-	212	106
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	14,729	-	-	-	-	-	-	14,729	14,729
6	463-00 Measuring Structures	5,380	-	-	-	-	-	-	5,380	5,380
7	464-00 Other Structures & Improvements	6,014	-	-	-	-	-	-	6,014	6,014
8	465-00 Mains	730,138	43,151	7,726	323	3,648	-	-	784,986	764,501
9	465-00 Mains - INSPECTION	3,164	-	626	-	296	-	-	4,086	3,625
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	108,581	-	1,300	62	614	-	-	110,557	109,569
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	-	-	-	-	-	-	28,208	28,208
17	467-20 Telemetering	6,498	-	50	2	24	-	-	6,574	6,536
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	913,755	43,363	9,702	387	4,582	-	-	971,789	949,711
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,414	-	-	-	-	-	-	3,414	3,414
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	15,643	-	-	-	-	-	-	15,643	15,643
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	664,510	-	15,448	-	7,294	(3,687)	-	683,565	674,038
29	473-00 Services - LILO	43,101	-	-	-	-	(77)	-	43,024	43,063
30	474-00 House Regulators & Meter Installations	134,715	-	10,647	6	5,027	-	-	150,395	142,555
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
33	475-00 Mains	869,468	-	16,788	129	7,927	(1,021)	-	893,291	881,380
34	475-00 Mains - LILO	39,764	-	-	-	-	(47)	-	39,717	39,741
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	81,311	-	3,700	176	1,747	-	-	86,934	84,123
37	477-00 Telemetering	6,211	-	180	1	85	-	-	6,477	6,344
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	192,977	-	10,647	-	-	(3,827)	-	199,797	196,387
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,090,008	-	57,410	312	22,080	(8,659)	-	2,161,151	2,125,580
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	-	-	120	10	57	-	-	187	94
49	418-10 Bio Gas Purification Overhaul	-	-	387	15	-	-	-	402	201
50	418-20 Bio Gas Purification Upgrader	-	-	1,547	60	-	-	-	1,607	804
51	474-10 Bio Gas Reg & Meter Installations	-	-	1,129	19	533	-	-	1,681	841
52	478-30 Bio Gas Meters	-	-	21	19	-	-	-	40	20
53	TOTAL BIO-GAS	-	-	3,204	123	590	-	-	3,917	1,959

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	$ -	$ 1,386	$ -	$ 654	$ -	$ -	$ 2,040	$ 1,020
3	476-20 NG Transportation LNG Dispensing Equipment	-	-	1,180	-	557	-	-	1,737	869
4	476-30 NG Transportation CNG Foundations	-	-	306	-	144	-	-	450	225
5	476-40 NG Transportation LNG Foundations	-	-	260	-	123	-	-	383	192
6	476-50 NG Transportation LNG Pumps	-	-	560	-	264	-	-	824	412
7	476-60 NG Transportation CNG Dehydrator	-	-	108	-	51	-	-	159	80
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-	-	3,800	-	1,793	-	-	5,593	2,797
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	20,142	-	129	-	-	-	-	20,271	20,207
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	7,898	-	-	-	-	(6)	-	7,892	7,895
16	- Masonry Buildings	83,528	-	2,555	-	-	-	-	86,083	84,806
17	- Leasehold Improvement	161	-	100	-	-	-	-	261	211
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,452	-	120	-	-	-	-	3,572	3,512
20	483-40 GP Furniture	20,685	-	170	-	-	(1,462)	-	19,393	20,039
21	483-10 GP Computer Hardware	14,304	-	6,400	171	-	-	-	20,875	17,590
22	483-20 GP Computer Software	1,504	-	-	-	-	(198)	514	1,820	1,662
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	1,474	-	232	-	-	(424)	-	1,282	1,378
26	484-00 Vehicles - Leased	26,997	-	3,710	-	-	(2,226)	-	28,481	27,739
27	485-10 Heavy Work Equipment	270	-	-	-	-	-	-	270	270
28	485-20 Heavy Mobile Equipment	862	-	161	-	-	-	-	1,023	943
29	486-00 Small Tools & Equipment	39,243	-	3,265	-	-	(1,806)	-	40,702	39,973
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,759	-	25	-	-	(1)	-	7,783	7,771
34	- Radio	5,451	-	45	-	-	(952)	-	4,544	4,998
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	233,754	-	16,912	171	-	(7,075)	514	244,276	239,015
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,388,861	$ 43,363	$ 102,889	$ 1,256	$ 30,054	$ (27,835)	$ 3,692	$ 3,542,280	$ 3,472,509
43										
44	Cross Reference	- Sect 7-TAB 7.1, Schedule 39							- Sect 7-TAB 7.1, Schedule 39	
45			- Sect 7-TAB 7.1, Schedule 42							- Sect 7-TAB 7.1, Schedule 54

FORTISBC ENERGY INC. - Mainland

May 4, 2011 Section 7
TAB 7.1
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,167	-	325	-	-	-	-	44,492	44,330
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	-	-	-	-	-	-	1,211	1,211
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	40,420	50,225	5,400	140	-	(2,722)	-	93,463	120,117
17	402-02 Application Software - 20%	16,878	-	5,400	81	-	(1,949)	-	20,410	18,644
18	TOTAL INTANGIBLE	105,154	50,225	11,125	221	-	(4,671)	-	162,054	186,779
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	146	-	50	-	17	-	-	213	180
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	14,112	-	-	-	-	-	15,040	7,984
30	442-00 Structures & Improvements (Tilbury)	4,959	588	-	-	-	-	-	5,547	5,253
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,658	-	2,050	63	714	(681)	-	28,804	27,731
36	TOTAL MANUFACTURED	50,400	14,700	2,100	63	731	(681)	-	67,313	58,857

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	212	-	-	-	-	-	-	212	212
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	14,729	-	-	-	-	-	-	14,729	14,729
6	463-00 Measuring Structures	5,380	-	-	-	-	-	-	5,380	5,380
7	464-00 Other Structures & Improvements	6,014	-	-	-	-	-	-	6,014	6,014
8	465-00 Mains	784,986	1,223	22,196	928	7,731	(1,065)	-	815,999	800,493
9	465-00 Mains - INSPECTION	4,086	-	1,531	-	533	-	-	6,150	5,118
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	110,557	-	4,021	191	1,401	(547)	-	115,623	113,090
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	-	-	-	-	-	-	28,208	28,208
17	467-20 Telemetering	6,574	-	736	32	257	(481)	-	7,118	6,846
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	971,789	1,223	28,484	1,151	9,922	(2,093)	-	1,010,476	991,133
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,414	-	-	-	-	-	-	3,414	3,414
25	471-00 Distribution Land Rights	-	-	50	-	-	-	-	50	25
26	472-00 Structures & Improvements	15,643	-	-	-	-	-	-	15,643	15,643
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	683,565	-	16,950	-	5,904	(2,947)	-	703,472	693,519
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	150,395	-	242	-	84	(1,783)	-	148,938	149,667
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	-	-	11,074	-	3,857	-	-	14,931	7,466
33	475-00 Mains	893,291	-	23,037	177	8,025	(2,834)	-	921,696	907,494
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	86,934	-	2,930	139	1,021	(542)	-	90,482	88,708
37	477-00 Telemetering	6,477	-	650	5	226	(120)	-	7,238	6,858
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	199,797	-	11,316	-	-	(3,915)	-	207,198	203,498
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,161,151	-	66,249	321	19,117	(12,141)	-	2,234,697	2,197,924
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	187	-	203	-	71	-	-	461	324
49	418-10 Bio Gas Purification Overhaul	402	-	413	-	-	-	-	815	609
50	418-20 Bio Gas Purification Upgrader	1,607	-	1,650	-	-	-	-	3,257	2,432
51	474-10 Bio Gas Reg & Meter Installations	1,681	-	406	-	141	-	-	2,228	1,955
52	478-30 Bio Gas Meters	40	-	406	-	-	-	-	446	243
53	TOTAL BIO-GAS	3,917	-	3,078	-	212	-	-	7,207	5,562

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,040	$ -	$ 1,540	$ -	$ 536	$ -	$ -	$ 4,116	$ 3,078
3	476-20 NG Transportation LNG Dispensing Equipment	1,737	-	1,180	-	411	-	-	3,328	2,533
4	476-30 NG Transportation CNG Foundations	450	-	340	-	118	-	-	908	679
5	476-40 NG Transportation LNG Foundations	383	-	260	-	91	-	-	734	559
6	476-50 NG Transportation LNG Pumps	824	-	560	-	195	-	-	1,579	1,202
7	476-60 NG Transportation CNG Dehydrator	159	-	120	-	42	-	-	321	240
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,593	-	4,000	-	1,393	-	-	10,986	8,290
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	20,271	-	2,000	-	-	-	-	22,271	21,271
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	7,892	-	-	-	-	-	-	7,892	7,892
16	- Masonry Buildings	86,083	7,245	3,777	-	-	-	-	97,105	91,594
17	- Leasehold Improvement	261	3,058	80	-	-	-	-	3,399	4,888
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,572	332	507	-	-	-	-	4,411	4,344
20	483-40 GP Furniture	19,393	2,459	1,536	-	-	(567)	-	22,821	23,711
21	483-10 GP Computer Hardware	20,875	3,151	7,200	192	-	(1,517)	-	29,901	28,724
22	483-20 GP Computer Software	1,820	-	-	-	-	(475)	-	1,345	1,583
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	1,282	-	465	-	-	(14)	-	1,733	1,508
26	484-00 Vehicles - Leased	28,481	-	3,180	-	-	(1,908)	-	29,753	29,117
27	485-10 Heavy Work Equipment	270	-	-	-	-	-	-	270	270
28	485-20 Heavy Mobile Equipment	1,023	-	200	-	-	-	-	1,223	1,123
29	486-00 Small Tools & Equipment	40,702	-	3,009	-	-	(884)	-	42,827	41,765
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,783	-	115	-	-	-	-	7,898	7,841
34	- Radio	4,544	-	45	-	-	(7)	-	4,582	4,563
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	244,276	16,245	22,114	192	-	(5,372)	-	277,455	270,216
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,542,280	$ 82,393	$ 137,150	$ 1,948	$ 31,375	$ (24,958)	$ -	$ 3,770,188	$ 3,718,759
43										
44	Cross Reference	- Sect 7-TAB 7.1, Schedule 40							- Sect 7-TAB 7.1, Schedule 40	
45			- Sect 7-TAB 7.1, Schedule 42							- Sect 7-TAB 7.1, Schedule 57

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,492	-	328	-	-	-	-	44,820	44,656
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	-	-	-	-	-	-	1,211	1,211
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	93,463	-	5,400	140	-	(6,015)	-	92,988	93,226
17	402-02 Application Software - 20%	20,410	-	5,400	81	-	(2,997)	-	22,894	21,652
18	TOTAL INTANGIBLE	162,054	-	11,128	221	-	(9,012)	-	164,391	163,223
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	213	-	-	-	-	-	-	213	213
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,040	-	-	-	-	-	-	15,040	15,040
30	442-00 Structures & Improvements (Tilbury)	5,547	-	-	-	-	-	-	5,547	5,547
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	28,804	-	450	14	164	(149)	-	29,283	29,044
36	TOTAL MANUFACTURED	67,313	-	450	14	164	(149)	-	67,792	67,553

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	212	-	-	-	-	-	-	212	212
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	14,729	-	-	-	-	-	-	14,729	14,729
6	463-00 Measuring Structures	5,380	-	-	-	-	-	-	5,380	5,380
7	464-00 Other Structures & Improvements	6,014	-	-	-	-	-	-	6,014	6,014
8	465-00 Mains	815,999	-	18,722	783	6,832	(899)	-	841,437	828,718
9	465-00 Mains - INSPECTION	6,150	-	1,342	-	490	-	-	7,982	7,066
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	115,623	-	3,369	160	1,230	(458)	-	119,924	117,774
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	-	-	-	-	-	-	28,208	28,208
17	467-20 Telemetering	7,118	-	935	40	341	(611)	-	7,823	7,471
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	1,010,476	-	24,368	983	8,893	(1,968)	-	1,042,752	1,026,614
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,414	-	-	-	-	-	-	3,414	3,414
25	471-00 Distribution Land Rights	50	-	50	-	-	-	-	100	75
26	472-00 Structures & Improvements	15,643	-	-	-	-	-	-	15,643	15,643
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	703,472	-	18,700	-	6,824	(2,806)	-	726,190	714,831
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	148,938	-	189	-	69	(284)	-	148,912	148,925
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	14,931	-	11,500	-	4,197	-	-	30,628	22,780
33	475-00 Mains	921,696	-	27,675	213	10,099	(3,404)	-	956,279	938,988
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	90,482	-	2,980	142	1,087	(551)	-	94,140	92,311
37	477-00 Telemetering	7,238	-	450	4	164	(83)	-	7,773	7,506
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	207,198	-	11,689	-	-	(3,915)	-	214,972	211,085
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,234,697	-	73,233	359	22,440	(11,043)	-	2,319,686	2,277,192
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	461	-	203	-	74	-	-	738	600
49	418-10 Bio Gas Purification Overhaul	815	-	513	-	-	-	-	1,328	1,072
50	418-20 Bio Gas Purification Upgrader	3,257	-	2,050	-	-	-	-	5,307	4,282
51	474-10 Bio Gas Reg & Meter Installations	2,228	-	406	-	148	-	-	2,782	2,505
52	478-30 Bio Gas Meters	446	-	406	-	-	-	-	852	649
53	TOTAL BIO-GAS	7,207	-	3,578	-	222	-	-	11,007	9,107

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued) -
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 4,116	$ -	$ 1,386	$ -	$ 506	$ -	$ -	$ 6,008	$ 5,062
3	476-20 NG Transportation LNG Dispensing Equipment	3,328	-	1,180	-	431	-	-	4,939	4,134
4	476-30 NG Transportation CNG Foundations	908	-	306	-	112	-	-	1,326	1,117
5	476-40 NG Transportation LNG Foundations	734	-	260	-	95	-	-	1,089	912
6	476-50 NG Transportation LNG Pumps	1,579	-	560	-	204	-	-	2,343	1,961
7	476-60 NG Transportation CNG Dehydrator	321	-	108	-	39	-	-	468	395
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	10,986	-	3,800	-	1,387	-	-	16,173	13,580
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,271	-	400	-	-	-	-	22,671	22,471
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	7,892	-	-	-	-	(3)	-	7,889	7,891
16	- Masonry Buildings	97,105	-	2,650	-	-	-	-	99,755	98,430
17	- Leasehold Improvement	3,399	-	100	-	-	(88)	-	3,411	3,405
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	4,411	-	100	-	-	-	-	4,511	4,461
20	483-40 GP Furniture	22,821	-	350	-	-	(1,954)	-	21,217	22,019
21	483-10 GP Computer Hardware	29,901	-	7,200	192	-	(6,489)	-	30,804	30,353
22	483-20 GP Computer Software	1,345	-	-	-	-	(44)	-	1,301	1,323
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	1,733	-	155	-	-	(34)	-	1,854	1,794
26	484-00 Vehicles - Leased	29,753	-	2,860	-	-	(1,716)	-	30,897	30,325
27	485-10 Heavy Work Equipment	270	-	-	-	-	-	-	270	270
28	485-20 Heavy Mobile Equipment	1,223	-	200	-	-	-	-	1,423	1,323
29	486-00 Small Tools & Equipment	42,827	-	3,024	-	-	(963)	-	44,888	43,858
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,898	-	30	-	-	(309)	-	7,619	7,759
34	- Radio	4,582	-	45	-	-	(34)	-	4,593	4,588
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	277,455	-	17,114	192	-	(11,634)	-	283,127	280,291
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,770,188	$ -	$ 133,671	$ 1,769	$ 33,106	$ (33,806)	$ -	$ 3,904,928	$ 3,837,558
43										
44	Cross Reference	- Sect 7-TAB 7.1, Schedule 41							- Sect 7-TAB 7.1, Schedule 41	
45			- Sect 7-TAB 7.1, Schedule 42							- Sect 7-TAB 7.1, Schedule 60

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	530	531
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	78
5	178-00 Organization Expense	728	1.00%	7	-	-	376	383
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	68	88
8	402-00 Utility Plant Acquisition Adjustment	62	23.66%	15	-	-	42	57
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	186	201
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,105	0.00%	-	-	-	651	651
12	461-10 Transmission Land Rights - Byron Creek	15	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	-	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	42,669	12.50%	5,334	-	(11,301)	21,918	15,951
17	402-02 Application Software - 20%	13,838	20.00%	2,768	-	(91)	3,955	6,632
18	TOTAL INTANGIBLE	104,301		8,238	-	(11,392)	27,748	24,594
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	3.28%	15	-	-	105	120
24	433-00 Manufact'd Gas - Equipment	146	6.30%	9	-	-	61	70
25	434-00 Manufact'd Gas - Gas Holders	358	3.90%	14	-	-	187	201
26	436-00 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	26	29
27	437-00 Manufact'd Gas - Measuring & Regulating Equipme	309	19.50%	60	-	-	212	272
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,959	3.65%	181	-	-	2,431	2,612
31	443-00 Gas Holders - Storage (Tilbury)	16,494	2.18%	360	-	-	10,043	10,403
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,407	3.36%	854	-	(709)	9,044	9,189
36	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	-	0.00%	-	-	-	-	-
37	TOTAL MANUFACTURED	49,149		1,496	-	(709)	22,110	22,897

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	106	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	14,729	3.84%	566	-	-	5,787	6,353
6	463-00 Measuring Structures	5,380	4.27%	230	-	-	1,501	1,731
7	464-00 Other Structures & Improvements	6,014	2.88%	173	-	-	1,547	1,720
8	465-00 Mains	764,501	1.63%	12,110	-	-	193,490	205,600
9	465-00 Mains - INSPECTION	3,625	14.87%	539	-	-	633	1,172
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	5.00%	49	-	-	840	889
13	466-00 Compressor Equipment	109,569	3.18%	3,484	-	-	38,207	41,691
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	94	196
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	7.19%	2,028	-	-	7,258	9,286
17	467-20 Telemetering	6,536	1.33%	87	-	-	6,193	6,280
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	4.01%	2	-	-	2	4
20	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	295	313
21	TOTAL TRANSMISSION	949,711		19,388	-	-	256,248	275,636
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,414	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	15,643	3.60%	563	-	-	3,713	4,276
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	22	27
28	473-00 Services	674,038	2.25%	15,166	-	(1,233)	111,297	125,230
29	473-00 Services - LILO	43,063	2.20%	947	-	(40)	913	1,820
30	474-00 House Regulators & Meter Installations	142,555	5.21%	7,427	-	-	4,232	11,659
31	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	352	704
32	477-00 Meters/Regulators Installations	-	0.00%	-	-	-	-	-
33	475-00 Mains	881,380	1.89%	16,658	-	(423)	267,780	284,015
34	475-00 Mains - LILO	39,741	2.00%	795	-	(29)	794	1,560
35	476-00 Compressor Equipment	1,026	25.04%	257	-	-	546	803
36	477-00 Measuring & Regulating Equipment	84,123	5.72%	4,812	-	-	17,571	22,383
37	477-00 Telemetering	6,344	0.25%	16	-	-	6,334	6,350
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	204	204
39	478-10 Meters	196,387	5.31%	10,428	-	(3,827)	55,075	61,676
40	478-11 Meters - LILO	10,027	3.29%	330	-	-	330	660
41	478-20 Instruments	11,501	4.03%	463	-	-	463	926
42	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,125,580		58,219	-	(5,552)	469,652	522,319
44								
45	**BIO GAS**							
46	472-00 Bio Gas Struct. & Improvements	-	3.60%	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	1.89%	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	94	1.89%	2	-	-	-	2
49	418-10 Bio Gas Purification Overhaul	201	13.33%	-	-	-	-	-
50	418-20 Bio Gas Purification Upgrader	804	6.67%	-	-	-	-	-
51	474-10 Bio Gas Reg & Meter Installations	841	5.21%	44	-	-	-	44
52	478-30 Bio Gas Meters	20	5.31%	1	-	-	-	1
53	TOTAL BIO-GAS	1,959		47	-	-	-	47

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ 1,020	5.00%	$ 51	$ -	$ -	$ -	$ 51
3	476-20 NG Transportation LNG Dispensing Equipment	869	5.00%	43	-	-	-	43
4	476-30 NG Transportation CNG Foundations	225	5.00%	11	-	-	-	11
5	476-40 NG Transportation LNG Foundations	192	5.00%	10	-	-	-	10
6	476-50 NG Transportation LNG Pumps	412	10.00%	41	-	-	-	41
7	476-60 NG Transportation CNG Dehydrator	80	5.00%	4	-	-	-	4
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	2,797		160	-	-	-	160
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	20,207	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	7,895	3.67%	290	-	(6)	2,020	2,304
16	- Masonry Buildings	84,806	2.50%	2,120	-	-	11,549	13,669
17	- Leasehold Improvement	211	0.00%	37	-	-	124	161
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,512	6.67%	234	-	-	(366)	(132)
20	483-40 GP Furniture	20,039	5.00%	1,002	-	(1,462)	14,804	14,344
21	483-10 GP Computer Hardware	17,590	20.00%	3,518	-	-	4,813	8,331
22	483-20 GP Computer Software	1,662	12.50%	208	-	(198)	772	782
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	1,378	7.70%	106	-	(424)	764	446
26	484-00 Vehicles - Leased	27,739	0.00%	2,911	-	(2,226)	14,061	14,746
27	485-10 Heavy Work Equipment	270	6.64%	18	-	-	(202)	(184)
28	485-20 Heavy Mobile Equipment	943	8.48%	80	-	-	470	550
29	486-00 Small Tools & Equipment	39,973	5.00%	1,999	-	(1,806)	16,305	16,498
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	8	10
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,771	6.67%	518	-	(1)	3,608	4,125
34	- Radio	4,998	6.67%	333	-	(952)	3,008	2,389
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	239,015		13,376	-	(7,075)	71,768	78,069
37								
38	**UNCLASSIFIED PLANT**							
39	499 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,472,509		$ 100,924	$ -	$ (24,728)	$ 847,526	$ 923,722
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,301)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA			(47)				
46	**Net Depreciation Expense**			$ 99,576				
47								
48	Cross Reference	- Sect 7-TAB 7.1, Schedule 45		- Sect 7-TAB 7.1, Schedule 27			- Sect 7-TAB 7.1, Schedule 39	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	531	532
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	78	156
5	178-00 Organization Expense	728	1.00%	7	-	-	383	390
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	49	-	-	88	137
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	36	-	-	57	93
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	201	217
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,330	0.00%	-	-	-	651	651
12	461-10 Transmission Land Rights - Byron Creek	15	0.00%	-	-	-	19	$ 19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	-	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	120,117	12.50%	11,507	-	(2,722)	15,951	24,736
17	402-02 Application Software - 20%	18,644	20.00%	3,729	-	(1,949)	6,632	8,412
18	TOTAL INTANGIBLE	186,779		15,423	-	(4,671)	24,594	35,346
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	3.38%	16	-	-	120	136
24	433-00 Manufact'd Gas - Equipment	180	6.63%	12	-	-	70	82
25	434-00 Manufact'd Gas - Gas Holders	358	2.35%	8	-	-	201	209
26	436-00 Manufact'd Gas - Compressor Equipment	53	5.16%	3	-	-	29	32
27	437-00 Manufact'd Gas - Measuring & Regulating Equ	309	15.89%	49	-	-	272	321
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. H	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbu	7,984	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	5,253	3.57%	188	-	-	2,612	2,800
31	443-00 Gas Holders - Storage (Tilbury)	16,494	1.93%	318	-	-	10,403	10,721
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	27,731	4.24%	1,176	-	(681)	9,189	9,684
36	440/441-00 Land in Fee Simple and Land Rights (Mou	-	0.00%	-	-	-	-	-
37	TOTAL MANUFACTURED	58,857		1,770	-	(681)	22,897	23,986

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	212	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	14,729	3.74%	551	-	-	6,353	6,904
6	463-00 Measuring Structures	5,380	3.80%	204	-	-	1,731	1,935
7	464-00 Other Structures & Improvements	6,014	2.83%	170	-	-	1,720	1,890
8	465-00 Mains	800,493	1.44%	11,520	-	(1,065)	205,600	216,055
9	465-00 Mains - INSPECTION	5,118	14.87%	761	-	-	1,172	1,933
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	5.00%	49	-	-	889	938
13	466-00 Compressor Equipment	113,090	2.87%	3,246	-	(547)	41,691	44,390
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	196	298
15	467-00 Mt. Hayes - Measuring and Regulating Equipm	-	0.00%	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	4.27%	1,204	-	-	9,286	10,490
17	467-20 Telemetering	6,846	0.31%	21	-	(481)	6,280	5,820
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Cr	39	0.00%	-	-	-	4	4
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	313	328
21	TOTAL TRANSMISSION	991,133		17,843	-	(2,093)	275,636	291,386
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,414	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	25	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	15,643	3.33%	521	-	-	4,276	4,797
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	27	32
28	473-00 Services	693,519	2.29%	15,882	-	(2,947)	125,230	138,165
29	473-00 Services - LILO	43,024	5.91%	2,543	-	-	1,820	4,363
30	474-00 House Regulators & Meter Installations	149,667	7.44%	11,135	(5,451)	(1,783)	11,659	15,560
31	474-00 House Regulators & Meter Installations - LILO	16,070	3.72%	598	-	-	704	1,302
32	477-00 Meters/Regulators Installations	7,466	4.55%	340	-	-	-	340
33	475-00 Mains	907,494	1.48%	13,431	-	(2,834)	284,015	294,612
34	475-00 Mains - LILO	39,717	4.54%	1,803	-	-	1,560	3,363
35	476-00 Compressor Equipment	1,026	26.54%	272	-	-	803	1,075
36	477-00 Measuring & Regulating Equipment	88,708	4.75%	4,214	-	(542)	22,383	26,055
37	477-00 Telemetering	6,858	0.25%	17	-	(120)	6,350	6,247
38	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	204	204
39	478-10 Meters	203,498	7.89%	16,056	1,046	(3,915)	61,676	74,863
40	478-11 Meters - LILO	10,027	5.23%	524	-	-	660	1,184
41	478-20 Instruments	11,501	3.15%	362	-	-	926	1,288
42	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,197,924		67,703	(4,405)	(12,141)	522,319	573,476
44								
45	**BIO GAS**							
46	472-00 Bio Gas Struct. & Improvements	-	3.60%	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	1.48%	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	324	1.48%	5	-	-	2	7
49	418-10 Bio Gas Purification Overhaul	609	13.33%	81	-	-	-	81
50	418-20 Bio Gas Purification Upgrader	2,432	6.67%	162	-	-	-	162
51	474-10 Bio Gas Reg & Meter Installations	1,955	7.44%	145	-	-	44	189
52	478-30 Bio Gas Meters	243	7.89%	19	-	-	1	20
53	TOTAL BIO-GAS	5,562		412	-	-	47	459

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipmer	$ 3,078	5.00%	$ 154	$ -	$ -	$ 51	$ 205
3	476-20 NG Transportation LNG Dispensing Equipmen	2,533	5.00%	127	-	-	43	170
4	476-30 NG Transportation CNG Foundations	679	5.00%	34	-	-	11	45
5	476-40 NG Transportation LNG Foundations	559	5.00%	28	-	-	10	38
6	476-50 NG Transportation LNG Pumps	1,202	10.00%	120	-	-	41	161
7	476-60 NG Transportation CNG Dehydrator	240	5.00%	12	-	-	4	16
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	8,290		475	-	-	160	635
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	21,271	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	7,892	4.82%	380	-	-	2,304	2,684
16	- Masonry Buildings	91,594	2.23%	2,043	-	-	13,669	15,712
17	- Leasehold Improvement	4,888	0.00%	338	-	-	161	499
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	4,344	6.67%	277	-	-	(132)	145
20	483-40 GP Furniture	23,711	5.00%	1,117	-	(567)	14,344	14,894
21	483-10 GP Computer Hardware	28,724	20.00%	5,393	-	(1,517)	8,331	12,207
22	483-20 GP Computer Software	1,583	12.50%	198	-	(475)	782	505
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	1,508	5.16%	78	-	(14)	446	510
26	484-00 Vehicles - Leased	29,117	0.00%	3,086	-	(1,908)	14,746	15,924
27	485-10 Heavy Work Equipment	270	8.96%	24	-	-	(184)	(160)
28	485-20 Heavy Mobile Equipment	1,123	18.06%	203	-	-	550	753
29	486-00 Small Tools & Equipment	41,765	5.00%	2,088	-	(884)	16,498	17,702
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	10	12
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,841	6.67%	523	-	-	4,125	4,648
34	- Radio	4,563	6.67%	304	-	(7)	2,389	2,686
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	270,216		16,054	-	(5,372)	78,069	88,751
37								
38	**UNCLASSIFIED PLANT**							
39	499 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,718,759		$ 119,680	$ (4,405)	$ (24,958)	$ 923,722	$ 1,014,039
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,366)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA			(243)				
46	**Net Depreciation Expense**			$ 118,071				
47								
48	Cross Reference	- Sect 7-TAB 7.1, Schedule 48		- Sect 7-TAB 7.1, Schedule 28			- Sect 7-TAB 7.1, Schedule 40	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	532	533
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	156	234
5	178-00 Organization Expense	728	1.00%	7	-	-	390	397
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	49	-	-	137	186
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	36	-	-	93	129
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	217	233
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,656	0.00%	-	-	-	651	651
12	461-10 Transmission Land Rights - Byron Creek	15	0.00%	-	-	-	$ 19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	-	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	93,226	12.50%	11,653	-	(6,015)	24,736	30,374
17	402-02 Application Software - 20%	21,652	20.00%	4,330	-	(2,997)	8,412	9,745
18	TOTAL INTANGIBLE	163,223		16,170	-	(9,012)	35,346	42,504
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	3.38%	16	-	-	136	152
24	433-00 Manufact'd Gas - Equipment	213	6.63%	14	-	-	82	96
25	434-00 Manufact'd Gas - Gas Holders	358	2.35%	8	-	-	209	217
26	436-00 Manufact'd Gas - Compressor Equipment	53	5.16%	3	-	-	32	35
27	437-00 Manufact'd Gas - Measuring & Regulating Equ	309	15.89%	49	-	-	321	370
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. H	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbu	15,040	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	5,547	3.57%	198	-	-	2,800	2,998
31	443-00 Gas Holders - Storage (Tilbury)	16,494	1.93%	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	29,044	4.24%	1,231	-	(149)	9,684	10,766
36	440/441-00 Land in Fee Simple and Land Rights (Mou	-	0.00%	-	-	-	-	-
37	TOTAL MANUFACTURED	67,553		1,837	-	(149)	23,986	25,674

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	212	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	14,729	3.74%	551	-	-	6,904	7,455
6	463-00 Measuring Structures	5,380	3.80%	204	-	-	1,935	2,139
7	464-00 Other Structures & Improvements	6,014	2.83%	170	-	-	1,890	2,060
8	465-00 Mains	828,718	1.44%	11,934	-	(899)	216,055	227,090
9	465-00 Mains - INSPECTION	7,066	14.87%	1,051	-	-	1,933	2,984
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	971	5.00%	49	-	-	938	987
13	466-00 Compressor Equipment	117,774	2.87%	3,380	-	(458)	44,390	47,312
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	298	400
15	467-00 Mt. Hayes - Measuring and Regulating Equipm	-	0.00%	-	-	-	-	-
16	467-10 Measuring & Regulating Equipment	28,208	4.27%	1,204	-	-	10,490	11,694
17	467-20 Telemetering	7,471	0.31%	23	-	(611)	5,820	5,232
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Cr	39	0.00%	-	-	-	4	4
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	328	343
21	TOTAL TRANSMISSION	1,026,614		18,683	-	(1,968)	291,386	308,101
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,414	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	75	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	15,643	3.33%	521	-	-	4,797	5,318
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	32	37
28	473-00 Services	714,831	2.29%	16,370	-	(2,806)	138,165	151,729
29	473-00 Services - LILO	43,024	5.91%	2,543	-	-	4,363	6,906
30	474-00 House Regulators & Meter Installations	148,925	7.44%	11,080	-	(284)	15,560	26,356
31	474-00 House Regulators & Meter Installations - LILO	16,070	3.72%	598	-	-	1,302	1,900
32	477-00 Meters/Regulators Installations	22,780	4.55%	1,036	-	-	340	1,376
33	475-00 Mains	938,988	1.48%	13,897	-	(3,404)	294,612	305,105
34	475-00 Mains - LILO	39,717	4.54%	1,803	-	-	3,363	5,166
35	476-00 Compressor Equipment	1,026	26.54%	272	-	-	1,075	1,347
36	477-00 Measuring & Regulating Equipment	92,311	4.75%	4,385	-	(551)	26,055	29,889
37	477-00 Telemetering	7,506	0.25%	19	-	(83)	6,247	6,183
38	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	204	204
39	478-10 Meters	211,085	7.89%	16,655	-	(3,915)	74,863	87,603
40	478-11 Meters - LILO	10,027	5.23%	524	-	-	1,184	1,708
41	478-20 Instruments	11,501	3.15%	362	-	-	1,288	1,650
42	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,277,192		70,070	-	(11,043)	573,476	632,503
44								
45	**BIO GAS**							
46	472-00 Bio Gas Struct. & Improvements	-	3.60%	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	1.48%	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	600	1.48%	9	-	-	7	16
49	418-10 Bio Gas Purification Overhaul	1,072	13.33%	143	-	-	81	224
50	418-20 Bio Gas Purification Upgrader	4,282	6.67%	286	-	-	162	448
51	474-10 Bio Gas Reg & Meter Installations	2,505	7.44%	186	-	-	189	375
52	478-30 Bio Gas Meters	649	7.89%	51	-	-	20	71
53	TOTAL BIO-GAS	9,107		675	-	-	459	1,134

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipmer	$ 5,062	5.00%	$ 253	$ -	$ -	$ 205	$ 458
3	476-20 NG Transportation LNG Dispensing Equipmen	4,134	5.00%	207	-	-	170	377
4	476-30 NG Transportation CNG Foundations	1,117	5.00%	56	-	-	45	101
5	476-40 NG Transportation LNG Foundations	912	5.00%	46	-	-	38	84
6	476-50 NG Transportation LNG Pumps	1,961	10.00%	196	-	-	161	357
7	476-60 NG Transportation CNG Dehydrator	395	5.00%	20	-	-	16	36
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	13,580		778	-	-	635	1,413
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,471	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	7,891	4.82%	380	-	(3)	2,684	3,061
16	- Masonry Buildings	98,430	2.23%	2,195	-	-	15,712	17,907
17	- Leasehold Improvement	3,405	10.00%	340	-	(88)	499	751
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	4,461	6.67%	298	-	-	145	443
20	483-40 GP Furniture	22,019	5.00%	1,101	-	(1,954)	14,894	14,041
21	483-10 GP Computer Hardware	30,353	20.00%	6,070	-	(6,489)	12,207	11,788
22	483-20 GP Computer Software	1,323	12.50%	165	-	(44)	505	626
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	1,794	5.16%	93	-	(34)	510	569
26	484-00 Vehicles - Leased	30,325	0.00%	3,239	-	(1,716)	15,924	17,447
27	485-10 Heavy Work Equipment	270	8.96%	24	-	-	(160)	(136)
28	485-20 Heavy Mobile Equipment	1,323	18.06%	239	-	-	753	992
29	486-00 Small Tools & Equipment	43,858	5.00%	2,193	-	(963)	17,702	18,932
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	12	14
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,759	6.67%	518	-	(309)	4,648	4,857
34	- Radio	4,588	6.67%	306	-	(34)	2,686	2,958
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	280,291		17,163	-	(11,634)	88,751	94,280
37								
38	**UNCLASSIFIED PLANT**							
39	499 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,837,558		$ 125,376	$ -	$ (33,806)	$ 1,014,039	$ 1,105,609
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,423)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA			(429)				
46	**Net Depreciation Expense**			$ 123,524				
47								
48	Cross Reference	- Sect 7-TAB 7.1, Schedule 51		- Sect 7-TAB 7.1, Schedule 29			- Sect 7-TAB 7.1, Schedule 41	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 5,253	0.36%	$ 19	$ -	$ -	$ -	$ -	$ 19
3	443-00 Gas Holders - Storage (Tilbury)	16,494	0.40%	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	27,731	0.37%	103	-	-	-	-	103
5	TOTAL MANUFACTURED	58,857		188	-	-	-	-	188
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	14,729	0.18%	27	-	-	-	-	27
9	463-00 Measuring Structures	5,380	0.18%	10	-	-	-	-	10
10	464-00 Other Structures & Improvements	6,014	0.14%	8	-	-	-	-	8
11	465-00 Mains	800,493	0.14%	1,121	-	-	-	-	1,121
12	466-00 Compressor Equipment	113,090	0.28%	317	-	-	-	-	317
13	467-10 Measuring & Regulating Equipment	28,208	0.18%	51	-	-	-	-	51
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	-	3
15	TOTAL TRANSMISSION	991,133		1,537	-	-	-	-	1,537
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	15,643	0.16%	25	-	-	-	-	25
19	473-00 Services	693,519	1.07%	7,421	-	(9,209)	-	-	(1,788)
20	473-00 Services - LILO	43,024	2.86%	1,230	-	-	-	-	1,230
21	474-00 House Regulators & Meter Installations	149,667	0.75%	1,123	5,451	(2,700)	-	-	3,874
22	475-00 Mains	907,494	0.29%	2,632	-	(700)	-	-	1,932
23	475-00 Mains - LILO	39,717	0.98%	389	-	-	-	-	389
24	476-00 Compressor Equipment	1,026	11.43%	117	-	-	-	-	117
25	477-00 Measuring & Regulating Equipment	88,708	0.52%	461	-	-	-	-	461
26	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	203,498	0.50%	1,017	(1,046)	-	-	-	(29)
28	TOTAL DISTRIBUTION	2,197,924		14,471	4,405	(12,609)	-	-	6,267
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	324	0.29%	1	-	-	-	-	1
32	478-30 Bio Gas Meters	243	0.50%	1	-	-	-	-	1
33	TOTAL BIO-GAS	5,562		2	-	-	-	-	2
34									
35	TOTALS	$ 3,718,759		$ 16,198	$ 4,405	$ (12,609)	$ -	$ -	$ 7,994
36									
37	Cross Reference	- Sect 7-TAB 7.1, Schedule 48		- Sect 7-TAB 7.1, Schedule 28					- Sect 7-TAB 7.1, Schedule 40
38									

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 5,547	0.36%	$ 20	$ -	$ -	$ -	$ 19	$ 39
3	443-00 Gas Holders - Storage (Tilbury)	16,494	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	29,044	0.37%	107	-	-	-	103	210
5	TOTAL MANUFACTURED	67,553		193	-	-	-	188	381
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	14,729	0.18%	27	-	-	-	27	54
9	463-00 Measuring Structures	5,380	0.18%	10	-	-	-	10	20
10	464-00 Other Structures & Improvements	6,014	0.14%	8	-	-	-	8	16
11	465-00 Mains	828,718	0.14%	1,160	-	-	-	1,121	2,281
12	466-00 Compressor Equipment	117,774	0.28%	330	-	-	-	317	647
13	467-10 Measuring & Regulating Equipment	28,208	0.18%	51	-	-	-	51	102
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
15	TOTAL TRANSMISSION	1,026,614		1,589	-	-	-	1,537	3,126
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	15,643	0.16%	25	-	-	-	25	50
19	473-00 Services	714,831	1.07%	7,649	-	(9,232)	-	(1,788)	(3,371)
20	473-00 Services - LILO	43,024	2.86%	1,230	-	-	-	1,230	2,460
21	474-00 House Regulators & Meter Installations	148,925	0.75%	1,117	-	(2,700)	-	3,874	2,291
22	475-00 Mains	938,988	0.29%	2,723	-	(1,000)	-	1,932	3,655
23	475-00 Mains - LILO	39,717	0.98%	389	-	-	-	389	778
24	476-00 Compressor Equipment	1,026	11.43%	117	-	-	-	117	234
25	477-00 Measuring & Regulating Equipment	92,311	0.52%	480	-	-	-	461	941
26	477-10 Measuring & Regulating Equipment - Byron Cr	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	211,085	0.50%	1,055	-	-	-	(29)	1,026
28	TOTAL DISTRIBUTION	2,277,192		14,956	-	(12,932)	-	6,267	8,291
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	600	0.29%	2	-	-	-	1	3
32	478-30 Bio Gas Meters	649	0.50%	3	-	-	-	1	4
33	TOTAL BIO-GAS	9,107		5	-	-	-	2	7
34									
35	TOTALS	$ 3,837,558		$ 16,743	$ -	$ (12,932)	$ -	$ 7,994	$ 11,805
36									
37	Cross Reference	- Sect 7-TAB 7.1, Schedule 51		- Sect 7-TAB 7.1, Schedule 29				- Sect 7-TAB 7.1, Schedule 41	
38									

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Projected Additions	2011 Projected Retirements	Balance 12/31/2011	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 144,790	$ -	$ 6,818 *	$ -	$ 151,608	
4							
5	Transmission Contributions	-	-	3,900	-	3,900	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	19,358	-	-	(3,494)	15,864	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	164,148	-	10,718	(3,494)	171,372	- Sect 7-TAB 7.1, Schedule 39
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(36,157)	-	(3,231)	-	(39,388)	
21							
22	Transmission Contributions	-	-	(62)	-	(62)	
23							
24	Others	-	-	10	-	10	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(10,595)	-	(2,201)	3,494	(9,302)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(46,752)	-	(5,484)	3,494	(48,742)	- Sect 7-TAB 7.1, Schedule 39
32							
33	**NET CONTRIBUTIONS**	$ 117,396	$ -	$ 5,234	$ -	$ 122,630	
34	* Note: Includes Gateway contributions						

FORTISBC ENERGY INC. - Mainland

May 4, 2011

Section 7
TAB 7.1
Schedule 64

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 Forecast Additions	2012 Forecast Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 151,608	$ -	$ 6,091 *	$ -	$ 157,699	
4							
5	Transmission Contributions	3,900	-	10,750	-	14,650	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	15,864	-	-	(5,106)	10,758	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	171,372	-	16,841	(5,106)	183,107	- Sect 7-TAB 7.1, Schedule 40
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(39,388)	-	(4,468)	-	(43,856)	
21							
22	Transmission Contributions	(62)	-	(155)	-	(217)	
23							
24	Others	10	-	10	-	20	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(9,302)	-	(1,664)	5,106	(5,860)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(48,742)	-	(6,277)	5,106	(49,913)	- Sect 7-TAB 7.1, Schedule 40
32							
33	**NET CONTRIBUTIONS**	$ 122,630	$ -	$ 10,564	$ -	$ 133,194	
34	* Note: Includes Gateway contributions						

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 Forecast Additions	2013 Forecast Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 157,699	$ -	$ 6,150 *	$ -	$ 163,849	
4							
5	Transmission Contributions	14,650	-	750	-	15,400	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,758	-	-	(204)	10,554	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	183,107	-	6,900	(204)	189,803	- Sect 7-TAB 7.1, Schedule 41
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(43,856)	-	(4,645)	-	(48,501)	
21							
22	Transmission Contributions	(217)	-	(252)	-	(469)	
23							
24	Others	20	-	10	-	30	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(5,860)	-	(1,332)	204	(6,988)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(49,913)	-	(6,219)	204	(55,928)	- Sect 7-TAB 7.1, Schedule 41
32							
33	**NET CONTRIBUTIONS**	$ 133,194	$ -	$ 681	$ -	$ 133,875	
34	* Note: Includes Gateway contributions						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (21,177)	$ -	$ (2,764)	$ 733	$ (2,032)	$ -	$ -	$ -	$ (23,209)	$ (22,193)
3	Midstream Cost Reconciliation Account (MCRA)	3,505	-	20,547	(5,445)	15,102	-	-	-	18,607	11,056
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,935)	-	(2,859)	758	(2,101)	-	2,329	(617)	(8,325)	(8,130)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(2,709)	-	(372)	99	(273)	-	(7)	2	(2,987)	(2,848)
6	Revelstoke Propane Cost Deferral Account	(16)	-	279	(74)	205	-	-	-	189	86
7	SCP Mitigation Revenues Variance Account	(5,389)	-	(3,496)	969	(2,527)	1,736	-	-	(6,180)	(5,784)
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	10,617	-	17,800	(4,717)	13,083	(2,523)	-	-	21,177	15,897
11	NGV Conversion Grants	92	-	65	(17)	48	(51)	-	-	89	90
12	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
13	2010-2011 Biomethane Program Costs	-	-	-	-	-	-	-	-	-	-
14	2011 CNG and LNG Service Costs and Recoveries	-	-	-	-	-	-	-	-	-	-
15	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
16											
17	Non-Controllable Items										
18	Property Tax Deferral	(1,079)	-	(1,353)	359	(994)	185	-	-	(1,889)	(1,484)
19	Insurance Variance	(727)	-	(639)	169	(470)	-	-	-	(1,197)	(962)
20	Pension & OPEB Variance	1,592	-	7,982	-	7,982	-	-	-	9,574	5,583
21	BCUC Levies Variance	164	-	96	(25)	71	-	-	-	235	199
22	Interest Variance	(5,980)	-	(867)	230	(637)	722	-	-	(5,896)	(5,938)
23	Interest Variance - Funding benefits via Customer Deposits	843	-	118	(31)	87	(13)	-	-	917	880
24	Tax Variance Account	(3,207)	-	(4,025)	-	(4,025)	205	-	-	(7,027)	(5,117)
25	Olympics Security Costs Deferral	1,188	-	-	-	-	(806)	-	-	382	785
26	IFRS Conversion Costs	702	-	10	(3)	7	(196)	-	-	513	607
27	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
28	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
29											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 732	$ -	$ 31	$ (8)	$ 23	$ (88)	$ -	$ -	$ 667	$ 699
3	2010-2011 Revenue Requirement Application	234	-	-	-	-	(398)	-	-	(164)	35
4	2012-2013 Revenue Requirement Application	45	-	1,126	(298)	828	-	-	-	873	459
5	CCE CPCN Application	244	-	-	-	-	(38)	-	-	206	225
6	NGV for Transportation Application	-	-	-	-	-	-	-	-	-	-
7	Long Term Resource Plan Application	-	-	165	(44)	121	-	-	-	121	61
8											
9	Other										
10	Pension & OPEB Funding	(11,293)	-	(13,516)	-	(13,516)	-	-	-	(24,809)	(18,051)
11	Deferred Removal Costs	1,373	-	2,094	(555)	1,539	-	-	-	2,912	2,143
12	Gains and Losses on Asset Disposition	14,817	-	3,106	-	3,106	-	-	-	17,923	16,370
13	2010-2011 Customer Service O&M and COS	-	-	-	-	-	-	-	-	-	-
14	2011 Kootney River Crossing COS	-	-	-	-	-	-	-	-	-	-
15	Gas Asset Records Project	-	-	-	-	-	-	-	-	-	-
16	BC OneCall Project	-	-	-	-	-	-	-	-	-	-
17	IFRS Transitional Costs	(6,575)	-	-	-	-	-	-	-	(6,575)	(6,575)
18											
19	Residual Deferred Charges										
20	SCP Tax Reassessment	669	-	20	(5)	15	-	-	-	684	676
21	Earnings Sharing Mechanism	(6,081)	-	1,637	470	2,107	-	5,407	(1,433)	-	(3,041)
22	Carbon Tax Cost of Service	(66)	-	-	-	-	-	-	-	(66)	(66)
23	OSC Certification Compliance	(59)	-	-	-	-	-	-	-	(59)	(59)
24	FEI 2010 Revenue Surplus	(6,537)	-	-	-	-	6,537	-	-	-	(3,269)
25	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-
26											
27	Total Deferred Charges for Rate Base	$ (42,013)	$ -	$ 25,183	$ (7,436)	$ 17,747	$ 5,271	$ 7,729	$ (2,048)	$ (13,315)	$ (27,664)
28											
29	Cross Reference						- Sect 7-TAB 7.1, Schedule 27			- Sect 7-TAB 7.1, Schedule 39	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries		Balance 12/31/2012	Mid-Year Average 2012
								Rider	Tax on Rider		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (23,209)	$ -	$ 30,945	$ (7,736)	$ 23,209	$ -	$ -	$ -	$ -	$ (11,604)
3	Midstream Cost Reconciliation Account (MCRA)	18,607	-	-	-	-	-	(8,270)	2,067	12,404	15,506
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,325)	-	-	-	-	-	3,700	(925)	(5,550)	(6,937)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(2,987)	-	3,927	(982)	2,945	2	16	(4)	(27)	(1,507)
6	Revelstoke Propane Cost Deferral Account	189	-	(252)	63	(189)	-	-	-	0	94
7	SCP Mitigation Revenues Variance Account	(6,180)	-	-	-	-	2,515	-	-	(3,665)	(4,922)
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	21,177	-	17,800	(4,450)	13,350	(2,561)	-	-	31,965	26,571
11	NGV Conversion Grants	89	-	65	(16)	49	(24)	-	-	113	101
12	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
13	2010-2011 Biomethane Program Costs	-	897	-	-	-	(299)	-	-	598	748
14	2011 CNG and LNG Service Costs and Recoveries	-	-	(95)	24	(71)	24	-	-	(48)	(24)
15	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
16											
17	Non-Controllable Items										
18	Property Tax Deferral	(1,889)	-	-	-	-	1,099	-	-	(790)	(1,339)
19	Insurance Variance	(1,197)	-	-	-	-	1,197	-	-	-	(598)
20	Pension & OPEB Variance	9,574	-	-	-	-	(3,191)	-	-	6,383	7,978
21	BCUC Levies Variance	235	-	-	-	-	(234)	-	-	0	118
22	Interest Variance	(5,896)	-	-	-	-	2,490	-	-	(3,406)	(4,651)
23	Interest Variance - Funding benefits via Customer Deposits	917	-	-	-	-	(387)	-	-	530	723
24	Tax Variance Account	(7,027)	-	-	-	-	7,027	-	-	-	(3,513)
25	Olympics Security Costs Deferral	382	-	-	-	-	(194)	-	-	187	285
26	IFRS Conversion Costs	513	-	-	-	-	(257)	-	-	256	384
27	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
28	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
29											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 667	$ -	$ -	$ -	$ -	$ (169)	$ -	$ -	$ 498	$ 582
3	2010-2011 Revenue Requirement Application	(164)	-	-	-	-	164	-	-	(0)	(82)
4	2012-2013 Revenue Requirement Application	873	-	-	-	-	(436)	-	-	436	654
5	CCE CPCN Application	206	-	-	-	-	(56)	-	-	150	178
6	NGV for Transportation Application	-	147	-	-	-	(49)	-	-	98	123
7	Long Term Resource Plan Application	121	-	62	(16)	47	-	-	-	168	144
8											
9	Other										
10	Pension & OPEB Funding	(24,809)	-	(65,879)	-	(65,879)	-	-	-	(90,688)	(57,749)
11	Deferred Removal Costs	2,912	-	-	-	-	(1,456)	-	-	1,456	2,184
12	Gains and Losses on Asset Disposition	17,923	(6,575)	-	-	-	(567)	-	-	10,781	11,064
13	2010-2011 Customer Service O&M and COS	-	23,173	4,426	(1,106)	3,319	(2,897)	-	-	23,596	23,385
14	2011 Kootney River Crossing COS	-	120	-	-	-	(40)	-	-	80	100
15	Gas Asset Records Project	-	-	1,780	(445)	1,335	(267)	-	-	1,068	534
16	BC OneCall Project	-	-	1,113	(278)	834	(167)	-	-	668	334
17	IFRS Transitional Costs	(6,575)	6,575	62,806	-	62,806	(7,139)	-	-	55,667	27,834
18											
19	Residual Deferred Charges										
20	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
21	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
22	Carbon Tax Cost of Service	(66)	-	-	-	-	66	-	-	-	(33)
23	OSC Certification Compliance	(59)	-	-	-	-	59	-	-	-	(30)
24	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
25	Residual Rider Disposition	-	179	-	-	-	(179)	-	-	-	89
26											
27	Total Deferred Charges for Rate Base	$ (13,315)	$ 24,516	$ 56,698	$ (14,943)	$ 41,755	$ (5,928)	$ (4,554)	$ 1,138	$ 43,613	$ 27,407
28											
29	Cross Reference						- Sect 7-TAB 7.1, Schedule 28			- Sect 7-TAB 7.1, Schedule 40	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Midstream Cost Reconciliation Account (MCRA)	12,404	-	-	-	-	-	(8,270)	2,067	6,202	9,303
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(5,550)	-	-	-	-	-	3,700	(925)	(2,775)	(4,162)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(27)	-	-	-	-	2	11	(3)	(17)	(22)
6	Revelstoke Propane Cost Deferral Account	0	-	-	-	-	-	-	-	0	0
7	SCP Mitigation Revenues Variance Account	(3,665)	-	-	-	-	2,150	-	-	(1,514)	(2,590)
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	31,965	-	17,800	(4,450)	13,350	(3,950)	-	-	41,365	36,665
11	NGV Conversion Grants	113	-	65	(16)	49	(37)	-	-	125	119
12	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
13	2010-2011 Biomethane Program Costs	598	-	-	-	-	(299)	-	-	299	449
14	2011 CNG and LNG Service Costs and Recoveries	(48)	-	-	-	-	24	-	-	(24)	(36)
15	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
16											
17	Non-Controllable Items										
18	Property Tax Deferral	(790)	-	-	-	-	395	-	-	(395)	(593)
19	Insurance Variance	-	-	-	-	-	-	-	-	-	-
20	Pension & OPEB Variance	6,383	-	-	-	-	(3,191)	-	-	3,191	4,787
21	BCUC Levies Variance	0	-	-	-	-	-	-	-	0	0
22	Interest Variance	(3,406)	-	-	-	-	1,703	-	-	(1,702)	(2,554)
23	Interest Variance - Funding benefits via Customer Deposits	530	-	-	-	-	(265)	-	-	265	397
24	Tax Variance Account	-	-	-	-	-	-	-	-	-	-
25	Olympics Security Costs Deferral	187	-	-	-	-	(187)	-	-	0	94
26	IFRS Conversion Costs	256	-	-	-	-	(256)	-	-	0	128
27	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
28	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
29											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 498	$ -	$ -	$ -	$ -	$ (169)	$ -	$ -	$ 329	$ 414
3	2010-2011 Revenue Requirement Application	(0)	-	-	-	-	-	-	-	(0)	-
4	2012-2013 Revenue Requirement Application	436	-	-	-	-	(436)	-	-	(0)	218
5	CCE CPCN Application	150	-	-	-	-	(56)	-	-	93	122
6	NGV for Transportation Application	98	-	-	-	-	(49)	-	-	49	74
7	Long Term Resource Plan Application	168	-	178	(45)	134	(151)	-	-	151	159
8											
9	Other										
10	Pension & OPEB Funding	(90,688)	-	(4,340)	-	(4,340)	-	-	-	(95,028)	(92,858)
11	Deferred Removal Costs	1,456	-	-	-	-	(1,456)	-	-	-	728
12	Gains and Losses on Asset Disposition	10,781	-	-	-	-	(567)	-	-	10,213	10,497
13	2010-2011 Customer Service O&M and COS	23,596	-	-	-	-	(3,312)	-	-	20,285	21,940
14	2011 Kootney River Crossing COS	80	-	-	-	-	(40)	-	-	40	60
15	Gas Asset Records Project	1,068	-	2,003	(501)	1,502	(567)	-	-	2,003	1,535
16	BC OneCall Project	668	-	1,113	(278)	834	(334)	-	-	1,168	918
17	IFRS Transitional Costs	55,667	-	-	-	-	(7,139)	-	-	48,528	52,098
18											
19	Residual Deferred Charges										
20	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
21	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
22	Carbon Tax Cost of Service	-	-	-	-	-	-	-	-	-	-
23	OSC Certification Compliance	-	-	-	-	-	-	-	-	-	-
24	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
25	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-
26											
27	Total Deferred Charges for Rate Base	$ 43,613	$ -	$ 16,818	$ (5,290)	$ 11,529	$ (18,187)	$ (4,559)	$ 1,139	$ 33,536	$ 38,574
28											
29	Cross Reference						- Sect 7-TAB 7.1, Schedule 29			- Sect 7-TAB 7.1, Schedule 41	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 4,108	$ 2,785	$ 5,900	$ 5,900	$ 3,115	- Sect 7-TAB 7.1, Schedule 75
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(5,525)	(6,063)	(4,474)	(4,474)	1,589	
9							
10	Withholdings From Employees	(3,809)	(3,256)	(5,061)	(5,061)	(1,805)	
11							
12	Subtotal	(5,226)	(6,534)	(3,635)	(3,635)	2,899	- Sect 7-TAB 7.1, Schedule 39
13							
14	**Other Working Capital Items**						
15	Construction Advances	(659)	(670)	(620)	(620)	50	
16	Transmission Line Pack Gas	4,451	4,731	2,888	2,888	(1,843)	
17	Gas in Storage	130,883	114,804	99,511	99,511	(15,293)	
18	Inventory - Materials & Supplies	580	1,226	1,378	1,378	152	
19							
20	Subtotal	135,255	120,091	103,157	103,157	(16,934)	- Sect 7-TAB 7.1, Schedule 39
21							
22	Total	$ 130,029	$ 113,557	$ 99,522	$ 99,522	$ (14,035)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 5,900	$ 6,315	$ 6,360	$ 460	- Sect 7-TAB 7.1, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(4,474)	(4,718)	(4,718)	(244)	
9						
10	Withholdings From Employees	(5,061)	(5,087)	(5,087)	(26)	
11						
12	Subtotal	(3,635)	(3,490)	(3,445)	190	- Sect 7-TAB 7.1, Schedule 40
13						
14	**Other Working Capital Items**					
15	Construction Advances	(620)	(620)	(620)	-	
16	Transmission Line Pack Gas	2,888	2,825	2,825	(63)	
17	Gas in Storage	99,511	97,294	97,294	(2,217)	
18	Inventory - Materials & Supplies	1,378	1,406	1,406	28	
19						
20	Subtotal	103,157	100,905	100,905	(2,252)	- Sect 7-TAB 7.1, Schedule 40
21						
22	Total	$ 99,522	$ 97,415	$ 97,460	$ (2,062)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 6,360	$ 7,360	$ 7,788	$ 1,428	- Sect 7-TAB 7.1, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(4,718)	(4,588)	(4,588)	130	
9						
10	Withholdings From Employees	(5,087)	(5,163)	(5,163)	(76)	
11						
12	Subtotal	(3,445)	(2,391)	(1,963)	1,482	- Sect 7-TAB 7.1, Schedule 41
13						
14	**Other Working Capital Items**					
15	Construction Advances	(620)	(620)	(620)	-	
16	Transmission Line Pack Gas	2,825	3,566	3,566	741	
17	Gas in Storage	97,294	97,242	97,242	(52)	
18	Inventory - Materials & Supplies	1,406	1,434	1,434	28	
19						
20	Subtotal	100,905	101,622	101,622	717	- Sect 7-TAB 7.1, Schedule 41
21						
22	Total	$ 97,460	$ 99,231	$ 99,659	$ 2,199	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Days	2011 Expenses	2011 Cash Working Capital	2012 Days	2012 Expenses	2012 Cash Working Capital	2013 Days	2013 Expenses	2013 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	38.9			39.0			39.1			- Sect 7-TAB 7.1, Schedule 76
4	Expense Lead Days	36.9			36.9			36.7			- Sect 7-TAB 7.1, Schedule 77
5											- Sect 7-TAB 7.1, Schedule 72
6	Net Lead/(Lag) Days	2.0	$ 1,076,784	$ 5,900	2.1	$ 1,097,536	$ 6,315	2.4	$ 1,119,259	$ 7,360	- Sect 7-TAB 7.1, Schedule 73
7											- Sect 7-TAB 7.1, Schedule 74
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	38.9			39.0			39.1			- Sect 7-TAB 7.1, Schedule 76
13	Expense Lead Days	36.9			36.9			36.6			- Sect 7-TAB 7.1, Schedule 77
14											- Sect 7-TAB 7.1, Schedule 72
15	Net Lead/(Lag) Days	2.0	$ 1,076,784	$ 5,900	2.1	$ 1,105,368	$ 6,360	2.5	$ 1,137,037	$ 7,788	- Sect 7-TAB 7.1, Schedule 73
16											- Sect 7-TAB 7.1, Schedule 74
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 45			$ 428	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Revenue At 2011 Rates	2011 Lag Days Service to Collection	2011 Dollar Days	2012 Revenue At 2011 Rates	2012 Lag Days Service to Collection	2012 Dollar Days	2013 Revenue At 2011 Rates	2013 Lag Days Service to Collection	2013 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											
3	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.1, Schedule 14
4	Residential and Commercial	$ 1,113,072	38.3	$ 42,677,491	$ 1,112,451	38.3	$ 42,652,706	$ 1,112,245	38.3	$ 42,643,851	- Sect 7-TAB 7.1, Schedule 16
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	72,494	45.0	3,264,961	73,284	45.0	3,300,706	74,271	45.0	3,345,314	
6	NGV Fuel - Stations	500	41.7	20,842	500	41.7	20,842	500	41.7	20,842	
7											
8	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	47,551	42.5	2,023,169	48,215	42.6	2,052,985	48,280	42.6	2,056,086	
9											
10	Total Gas Sales	1,233,617	38.9	47,986,463	1,234,449	38.9	48,027,239	1,235,296	38.9	48,066,093	
11	Other Revenues										
12	Royalty Revenue (FEVI)	-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.1, Schedule 4
13	Late Payment Charges	2,335	38.3	89,419	2,333	38.3	89,362	2,333	38.3	89,365	- Sect 7-TAB 7.1, Schedule 18
14	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	79	38.5	3,041	- Sect 7-TAB 7.1, Schedule 19
15	Connection Charges	2,640	38.3	101,123	2,662	38.3	101,966	2,685	38.3	102,847	- Sect 7-TAB 7.1, Schedule 20
16	Other Utility Income	96	277.8	26,672	3,821	75.8	289,754	5,495	75.9	417,186	
17											
18											
19	Total Revenue	$ 1,238,767	38.9	$ 48,206,718	$ 1,243,344	39.0	$ 48,511,362	$ 1,245,888	39.1	$ 48,678,532	
20											
21											
22	**REVENUE, REVISED RATES**										
23											
24	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.1, Schedule 14
25	Residential and Commercial	$ 1,113,072	38.3	$ 42,677,491	$ 1,137,308	38.3	$ 43,605,941	$ 1,168,568	38.3	$ 44,803,727	- Sect 7-TAB 7.1, Schedule 16
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	72,494	45.0	3,264,961	76,390	45.0	3,440,959	81,416	45.1	3,667,952	
27	NGV Fuel - Stations	500	41.7	20,842	512	41.7	21,343	527	41.7	21,968	
28											
29	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	47,551	42.5	2,023,169	49,210	42.6	2,097,960	50,541	42.7	2,158,283	
30											
31	Total Gas Sales	1,233,617	38.9	47,986,463	1,263,419	38.9	49,166,203	1,301,052	38.9	50,651,930	
32	Other Revenues										- Sect 7-TAB 7.1, Schedule 18
33	Royalty Revenue (FEVI)	-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.1, Schedule 19
34	Late Payment Charges	2,335	38.3	89,419	2,333	38.3	89,362	2,333	38.3	89,365	- Sect 7-TAB 7.1, Schedule 20
35	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	79	38.5	3,041	
36	Connection Charges	2,640	38.3	101,123	2,662	38.3	101,966	2,685	38.3	102,847	
37	Other Utility Income	96	277.8	26,672	3,821	75.8	289,754	5,495	75.9	417,186	
38											
39											
40	Total Revenue	$ 1,238,767	38.9	$ 48,206,718	$ 1,272,314	39.0	$ 49,650,326	$ 1,311,644	39.1	$ 51,264,369	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011			2012			2013			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Sect 7-TAB 7.1, Schedule 4
4	Expenses	$ 184,625	25.5	$ 4,707,938	$ 192,742	25.5	$ 4,914,921	$ 203,365	25.5	$ 5,185,808	- Sect 7-TAB 7.1, Schedule 5
5	Transportation Costs	-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.1, Schedule 6
6	Gas Purchases (excl Royalty Credits)	661,224	40.2	26,581,204	659,338	40.2	26,505,387	658,568	40.2	26,474,434	
7											
8	Taxes Other Than Income										- Sect 7-TAB 7.1, Schedule 24
9	Property Taxes	48,858	2.0	97,716	49,656	2.0	99,312	51,239	2.0	102,478	- Sect 7-TAB 7.1, Schedule 25
10	Franchise Fees	8,567	420.3	3,600,710	8,570	420.3	3,601,971	8,555	420.3	3,595,666	- Sect 7-TAB 7.1, Schedule 26
11	Carbon Tax	125,849	29.1	3,662,213	153,578	29.1	4,469,116	167,344	29.1	4,869,715	
12	HST - Net *	10,547	38.8	409,207	25,394	38.8	985,294	25,446	38.8	987,298	
13	PST Component of HST (REC) *	5,779	37.1	214,404	(8,978)	33.8	(303,451)	(8,981)	33.8	(303,543)	- Sect 7-TAB 7.1, Schedule 30
14	Income Tax	31,335	15.2	476,292	17,236	15.2	261,987	13,724	15.2	208,605	- Sect 7-TAB 7.1, Schedule 31
15											- Sect 7-TAB 7.1, Schedule 32
16	Total	$ 1,076,784	36.9	$ 39,749,684	$ 1,097,536	36.9	$ 40,534,537	$ 1,119,260	36.7	$ 41,120,461	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Sect 7-TAB 7.1, Schedule 4
22	Expenses	$ 184,625	25.5	$ 4,707,938	$ 192,742	25.5	$ 4,914,921	$ 203,365	25.5	$ 5,185,808	- Sect 7-TAB 7.1, Schedule 5
23	Transportation Costs	-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.1, Schedule 6
24	Gas Purchases (excl Royalty Credits)	661,224	40.2	26,581,204	659,338	40.2	26,505,387	658,568	40.2	26,474,434	
25											
26	Taxes Other Than Income										- Sect 7-TAB 7.1, Schedule 24
27	Property Taxes	48,858	2.0	97,716	49,656	2.0	99,312	51,239	2.0	102,478	- Sect 7-TAB 7.1, Schedule 25
28	Franchise Fees	8,567	420.3	3,600,710	8,780	420.3	3,690,234	9,032	420.3	3,796,150	- Sect 7-TAB 7.1, Schedule 26
29	Carbon Tax	125,849	29.1	3,662,213	153,578	29.1	4,469,116	167,344	29.1	4,869,715	
30	HST - Net *	10,547	38.8	409,207	25,989	38.8	1,008,357	26,795	38.8	1,039,646	
31	PST Component of HST (REC) *	5,779	37.1	214,404	(9,192)	33.8	(310,693)	(9,467)	33.8	(319,970)	- Sect 7-TAB 7.1, Schedule 30
32	Income Tax	31,335	15.2	476,292	24,478	15.2	372,066	30,160	15.2	458,432	- Sect 7-TAB 7.1, Schedule 31
33											- Sect 7-TAB 7.1, Schedule 32
34	Total	$ 1,076,784	36.9	$ 39,749,684	$ 1,105,368	36.9	$ 40,748,700	$ 1,137,037	36.6	$ 41,606,693	

* 2011 was calculated using prior approved GST and PST method

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Plant & Equipment						
2	Net Book Value *	$ (2,507,135)	$ (2,625,708)	$ (2,532,958)	$ (2,663,168)	$ (2,708,937)	
3	Less: Undepreciated Capital Cost	(1,766,170)	(1,853,515)	(1,771,536)	(1,852,056)	(1,852,473)	
4		(740,965)	(772,193)	(761,422)	(811,112)	(856,464)	
5	Weighted Average Future Tax Rate	25.01%	25.00%	25.00%	25.00%	25.00%	
6		(185,322)	(193,048)	(190,356)	(202,778)	(214,116)	
7							
8	Total FIT Liability- After Tax (PP&E)	(185,322)	(193,048)	(190,356)	(202,778)	(214,116)	
9	Total FIT Liability- After Tax (Non-PP&E)	(7,216)	(27,038)	(8,805)	(5,259)	(1,385)	
10	Total FIT Liability- After Tax	(192,538)	(220,086)	(199,161)	(208,037)	(215,501)	
11							
12	Tax Gross Up	(64,216)	(73,362)	(66,387)	(69,346)	(71,834)	
13							
14	FIT Liability/Asset - End of Year	(256,754)	(293,448)	(265,547)	(277,383)	(287,335)	
15							
16	FIT Liability/Asset - Opening Balance	(275,646)	(290,862)	(256,754)	(265,548)	(277,382)	
17							- Sect 7-TAB 7.1, Schedule 39
18	FIT Liability/Asset - Mid Year	$ (266,200)	$ (292,155)	$ (261,151)	$ (271,465)	$ (282,358)	- Sect 7-TAB 7.1, Schedule 40
19							- Sect 7-TAB 7.1, Schedule 41
20							
21	Note: * Excludes Land, Software CIAC, and WIP.						

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 RATES							
2	Long-Term Debt		$ 1,534,686	60.52%	6.94%	4.20%	$ 106,577	- Sect 7-TAB 7.1, Schedule 82
3	Unfunded Debt		(13,239)	-0.52%	4.50%	-0.02%	(596)	
4	Common Equity		1,014,298	40.00%	10.00%	4.00%	101,396	
5								
6			$ 2,535,745	100.00%		8.18%	$ 207,377	- Sect 7-TAB 7.1, Schedule 39
7								
8								
9								
10	2011 REVISED RATES - PROJECTED							
11	Long-Term Debt		$ 1,534,686	60.52%	6.94%	4.20%	$ 106,577	- Sect 7-TAB 7.1, Schedule 82
12	Unfunded Debt	$ (13,239)						
13	Adjustment, Revised Rates	-	(13,239)	-0.52%	4.50%	-0.02%	(596)	
14	Common Equity		1,014,298	40.00%	10.00%	4.00%	101,396	
15								- Sect 7-TAB 7.1, Schedule 4
16			$ 2,535,745	100.00%		8.18%	$ 207,377	- Sect 7-TAB 7.1, Schedule 39

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2012 AT 2011 RATES							
2	Long-Term Debt		$ 1,582,117	57.82%	6.73%	3.89%	$ 106,548	- Sect 7-TAB 7.1, Schedule 83
3	Unfunded Debt		59,760	2.18%	2.75%	0.06%	1,643	
4	Common Equity		1,094,585	40.00%	7.53%	3.01%	82,260	
5								
6			$ 2,736,462	100.00%		6.96%	$ 190,451	- Sect 7-TAB 7.1, Schedule 40
7								
8								
9								
10	2012 REVISED RATES							
11	Long-Term Debt		$ 1,582,117	57.82%	6.73%	3.89%	$ 106,548	- Sect 7-TAB 7.1, Schedule 83
12	Unfunded Debt	$ 59,760						
13	Adjustment, Revised Rates	27	59,787	2.18%	2.75%	0.06%	1,644	
14	Common Equity		1,094,603	40.00%	9.50%	3.80%	103,987	
15								- Sect 7-TAB 7.1, Schedule 5
16			$ 2,736,507	100.00%		7.75%	$ 212,179	- Sect 7-TAB 7.1, Schedule 40

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 AT 2011 RATES							
2	Long-Term Debt		$ 1,582,515	56.76%	6.74%	3.83%	$ 106,730	- Sect 7-TAB 7.1, Schedule 84
3	Unfunded Debt		90,224	3.24%	3.75%	0.12%	3,383	
4	Common Equity		1,115,160	40.00%	5.08%	2.03%	56,647	
5								
6			$ 2,787,899	100.00%		5.98%	$ 166,759	- Sect 7-TAB 7.1, Schedule 41
7								
8								
9								
10	2013 REVISED RATES							
11	Long-Term Debt		$ 1,582,515	56.76%	6.74%	3.83%	$ 106,730	- Sect 7-TAB 7.1, Schedule 84
12	Unfunded Debt	$ 90,224						
13	Adjustment, Revised Rates	257	90,481	3.24%	3.75%	0.12%	3,393	
14	Common Equity		1,115,331	40.00%	9.50%	3.80%	105,956	
15								- Sect 7-TAB 7.1, Schedule 6
16			$ 2,788,327	100.00%		7.75%	$ 216,079	- Sect 7-TAB 7.1, Schedule 41

FORTISBC ENERGY INC. - Mainland

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	* $ 69,031	12.054%	$ 69,886	$ 8,424
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452
3										
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627
11										
12	2011 Medium Term Debt Issue- Series 25	1-Jul-2011	1-Jul-2021	5.650%	100,000	1,000	99,000	5.783%	50,411	2,915
13										
14	LILO Obligations - Kelowna							5.919%	25,729	1,523
15	LILO Obligations - Nelson							7.105%	4,110	292
16	LILO Obligations - Vernon							8.242%	12,267	1,011
17	LILO Obligations - Prince George							7.257%	31,571	2,291
18	LILO Obligations - Creston							6.509%	2,996	195
19										
20	Vehicle Lease Obligation							7.633%	13,455	1,027
21										
22	Sub-Total								$ 1,537,699	$ 106,786
23	Less: Fort Nelson Division Portion of Long Term Debt								3,013	209
24	Total								$ 1,534,686	$ 106,577
25										
26	*Includes adjustment of $10,943 for BC Hydro Premium (Series A).							Average Embedded Cost		6.94%
27										
28	Cross Reference								- Sect 7-TAB 7.1, Schedule 79	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 71,908	*	12.054%	$ 72,763	$ 8,771
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	**	10.461%	157,274	16,452
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14	LILO Obligations - Kelowna								6.398%	24,678	1,579
15	LILO Obligations - Nelson								7.606%	3,931	299
16	LILO Obligations - Vernon								8.833%	11,752	1,038
17	LILO Obligations - Prince George								7.769%	30,171	2,344
18	LILO Obligations - Creston								6.958%	2,860	199
19											
20	Vehicle Lease Obligation								5.007%	13,782	690
21											
22	Sub-Total									$ 1,587,211	$ 106,891
23	Less: Fort Nelson Division Portion of Long Term Debt									5,094	343
24	Total									$ 1,582,117	$ 106,548
25											
26	*Includes adjustment of $13,820 for BC Hydro Premium (Series A).									Average Embedded Cost	6.73%
27	**Includes adjustment of $0 for BC Hydro Premium (Series B).										
28	Cross Reference									- Sect 7-TAB 7.1, Schedule 80	

FORTISBC ENERGY INC. - Mainland

May 4, 2011

Section 7
TAB 7.1
Schedule 84

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	156,052	**	10.388%	158,280	16,442
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14	LILO Obligations - Kelowna								6.413%	23,749	1,523
15	LILO Obligations - Nelson								7.696%	3,794	292
16	LILO Obligations - Vernon								8.929%	11,323	1,011
17	LILO Obligations - Prince George								7.862%	29,142	2,291
18	LILO Obligations - Creston								7.050%	2,766	195
19											
20	Vehicle Lease Obligation								5.630%	13,640	768
21											
22	Sub-Total									$ 1,587,649	$ 107,076
23	Less: Fort Nelson Division Portion of Long Term Debt									5,134	346
24	Total									$ 1,582,515	$ 106,730
25											
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.74%
27	**Includes adjustment of $$1,006 for BC Hydro Premium (Series B).										
28	Cross Reference									- Sect 7-TAB 7.1, Schedule 81	

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Particulars	2012 Volumes (TJ)	2013 Volumes (TJ)	2012 Amortization ($000s)	2013 Amortization ($000s)	2012 Amortization of RSAM Unit Rider ($/GJ)	2013 Amortization of RSAM Unit Rider ($/GJ)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
RSAM (Rider 5) Calculation						
Schedule 1 - Residential	69,890.0	69,816.4			($0.032)	($0.032)
Schedule 2 - Small Commercial	23,438.1	23,331.9			($0.032)	($0.032)
Schedule 3 - Large Commercial	16,469.5	16,514.8			($0.032)	($0.032)
Schedule 23 - Large Commercial Transportation	7,151.3	7,485.3			($0.032)	($0.032)
	116,948.9	117,148.4	($3,716)	($3,711) [1]		

Note 1: RSAM Rider Change

In 2011, FortisBC Energy forecasts that there will be approximately $-2.1 million (net-of-tax) of RSAM additions. After offsetting the 2011 RSAM Rider recovery, the RSAM account including interest is now projected to be a credit balance of $-8 million on a net-of-tax basis by the end of 2011. The RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to be amortized in each year in 2012 and 2013 is a credit of $-2.8 million. On a pre-tax basis, this amounts to $3.7 million or a refund to the customer of $0.032/GJ in 2012, which is a $0.012 increase from the existing charge of $-0.02/GJ. The corresponding 2013 refund to the customer is $0.032/GJ.

2012 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2011 RSAM Balance
= 1/3 * ($-8,325 RSAM + $-34 RSAM Interest)
= 1/3 * $-8,359
= $-2,786 Net-of-tax amortization

2012 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-2,786 / (1 - 25%)
= $-3,716 Pre-tax amortization

2013 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2012 RSAM Balance
= 1/2 * ($-5,550 RSAM + $-22 RSAM Interest)
= 1/2 * $-5,572
= $-2,786 Net-of-tax amortization

2013 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-2,786 / (1 - 25%)
= $-3,711 Pre-tax amortization

7.2 Vancouver Island Schedules

Summary of Rate Change May 4, 2011 Section 7
TAB 7.2
Schedule 1

Vancouver Island

	2012 ($ Millions)		2013 ($ Millions)		Total ($ Millions)		Cross Reference
Volume/Revenue Related							
Royalty Revenues	$ 40.1		$ -		$ 40.1		
Surplus embedded in Existing Rates	(22.4)		-		(22.4)		
Customer Growth and Use Rates	7.8		(1.6)		6.3		
Change in Other Revenue	(2.9)	22.6	(0.0)	(1.6)	(2.9)	21.1	
Cost of Gas Changes							
Cost of Gas	(33.0)		2.1		(30.9)		
GCVA Additions	(8.1)	(41.1)	8.1	10.2	-	(30.9)	
O&M Changes							
Gross O&M Increases	2.5		0.2		2.8		
Less: Capitalized Overhead	(0.4)	2.2	(0.0)	0.2	(0.4)	2.4	
Depreciation & Removal Cost Provision							
Change in Depreciation Rates	(0.3)		-		(0.3)		
Tax Expense Impact of Depreciation Changes	2.4		0.4		2.8		
Depreciation from Net Additions	3.9		1.1		5.1		
Removal Cost Provision	3.6	9.6	0.1	1.7	3.7	11.3	
Amortization Expense							
CIAC	0.2		(0.0)		0.2		
Deferral Accounts	2.9	3.1	0.2	0.2	3.1	3.3	
Other							
Property and Other Taxes	0.3		0.4		0.7		
Other (NSP Provision, Transportation Costs, VINGPA)	3.6		0.0		3.6		
Income Tax Rate Change	(0.3)		(0.3)		(0.6)		
Other Income Tax Changes	(1.9)		3.4		1.6		
Financing Rate Changes	(1.9)		1.7		(0.2)		
Financing Changes	1.3		0.4		1.8		
Rate Base Growth	2.4	3.6	1.0	6.8	3.4	10.3	
Revenue Deficiency (Surplus)		**$ 0.0**		**$ 17.4**		**$ 17.4**	- Sect 7-TAB 7.2, Schedule 2 & 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Non-Bypass Sales	2012 Non-Bypass Transportation	2012 Bypass and Special Rates	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	COST OF SERVICE RATES							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 193,646	$ 174,353	$ -	$ 20,734	$ 195,087	$ 1,441	- Sect 7-TAB 7.2, Schedule 11
5								
6	Total Revenue	193,646	174,353	-	20,734	195,087	1,441	
7								
8	Less - Cost of Gas	(66,773)	(74,337)	-	-	(74,337)	(7,564)	- Sect 7-TAB 7.2, Schedule 13
9								
10	Gross Margin	$ 126,873	$ 100,016	$ -	$ 20,734	$ 120,750	$ (6,123)	
11								
12	Revenue Deficiency (Surplus)	$ (20,970)	$ 4	$ -	$ -	**$ 4**	$ 20,974	
13								
14	Revenue Deficiency (Surplus) as a % of Gross Margin	-16.53%	0.00%	0.00%	0.00%	0.00%		
15								
16	Revenue Deficiency (Surplus) as a % of Total Revenue	-10.83%	0.00%	0.00%	0.00%	0.00%		

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Non-Bypass Sales	2013 Non-Bypass Transportation	2013 Bypass and Special Rates	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	COST OF SERVICE RATES							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 195,087	$ 175,913	$ -	$ 20,734	$ 196,647	$ 1,560	- Sect 7-TAB 7.2, Schedule 12
5								
6	Total Revenue	195,087	175,913	-	20,734	196,647	1,560	
7								
8	Less - Cost of Gas	(74,337)	(76,399)	-	-	(76,399)	(2,062)	- Sect 7-TAB 7.2, Schedule 13
9								
10	Gross Margin	$ 120,750	$ 99,514	$ -	$ 20,734	$ 120,248	$ (502)	
11								
12	Revenue Deficiency (Surplus)	$ 4	$ 17,440	$ -	$ -	**$ 17,440**	$ 17,436	
13								
14	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	17.53%	0.00%	0.00%	14.50%		
15								
16	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	9.91%	0.00%	0.00%	8.87%		

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	ENERGY VOLUMES (TJ)					
2	Sales	11,491	12,433	11,696	(737)	- Sect 7-TAB 7.2, Schedule 7
3	Transportation	19,526	22,017	22,295	278	- Sect 7-TAB 7.2, Schedule 7
4		31,018	34,450	33,991	(459)	
5						
6	Average Rate per GJ					
7	Sales	$ 10.901	$ 12.872	$ 12.993	$ 0.121	
8	Transportation	$ 1.210	$ 0.931	$ 0.929	$ (0.002)	
9	Average	$ 4.800	$ 5.240	$ 5.080	$ (0.160)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 169,789	$ 182,402	$ 172,935	$ (9,467)	- Sect 7-TAB 7.2, Schedule 10
13	Transportation - Existing Rates	23,621	20,500	20,711	211	- Sect 7-TAB 7.2, Schedule 10
14	- Increase / (Decrease)	-	-	-	-	
15						
16	FEVI Revenue (Surplus) / Deficit	(44,527)	(22,367)	(20,970)	1,397	
17	**Total Revenue**	148,884	180,535	172,676	(7,859)	
18						
19	Cost of Gas Sold (Including Gas Lost)	74,343	107,311	66,773	(40,538)	- Sect 7-TAB 7.2, Schedule 13
20	Royalty Credit	(17,215)	(40,091)	(17,283)	22,808	
21	GCVA Amortization	(5,625)	-	3,282	3,282	
22	GCVA Additions	-	-	11,053	11,053	
23						
24	**Gross Margin**	97,381	113,314	108,851	(4,463)	
25						
26	Operation and Maintenance	26,859	28,136	28,136	0	- Sect 7-TAB 7.2, Schedule 21
27	Transportation Costs	4,019	4,122	4,480	358	
28	Property and Sundry Taxes	9,039	9,564	9,293	(271)	- Sect 7-TAB 7.2, Schedule 24
29	Depreciation and Amortization	19,831	25,577	24,962	(615)	- Sect 7-TAB 7.2, Schedule 27
30	NSP Provisions	1,400	(1,400)	(1,400)	-	
31	Interest on Subordinated Debt	261	-	-	-	
32	Other Operating Revenue	(690)	(9,752)	(7,629)	2,123	- Sect 7-TAB 7.2, Schedule 18
33	Sub-total	60,720	56,247	57,842	1,595	
34	Utility Income Before Income Taxes	36,660	57,067	51,009	(6,058)	
35						
36	Income Taxes	1,665	3,648	3,655	7	- Sect 7-TAB 7.2, Schedule 30
37						
38	**EARNED RETURN after VINGPA Adjustment**	$ 34,995	$ 53,419	47,354	$ (6,065)	- Sect 7-TAB 7.2, Schedule 30
39	VINGPA Adjustment (ends December 31, 2011)	(1,867)	(1,867)	(1,867)	-	
40	**EARNED RETURN before VINGPA Adjustment**	$ 36,862	$ 55,286	$ 49,221	$ (6,065)	- Sect 7-TAB 7.2, Schedule 79
41						
42						
43	**UTILITY RATE BASE**	$ 547,661	$ 728,993	$ 676,710	$ (52,283)	- Sect 7-TAB 7.2, Schedule 39
44						
45	**RATE OF RETURN ON UTILITY RATE BASE before VINGPA Adjustment**	6.73%	7.58%	7.27%	-0.31%	- Sect 7-TAB 7.2, Schedule 79

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 ---- Cost of Service Rates ---- Revised Revenue	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	11,696	11,774	-	11,774	78	- Sect 7-TAB 7.2, Schedule 8
3	Transportation	22,295	22,295	-	22,295	-	- Sect 7-TAB 7.2, Schedule 8
4		33,991	34,069	-	34,069	78	
5							
6	Average Rate per GJ						
7	Sales	$ 12.993	$ 14.808	$ -	$ 14.809	$ 1.816	
8	Transportation	$ 0.929	$ 0.930	$ -	$ 0.930	$ 0.001	
9	Average	$ 5.080	$ 5.726	$ -	$ 5.726	$ 0.646	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 172,935	$ 174,353	$ -	$ 174,353	$ 1,418	- Sect 7-TAB 7.2, Schedule 11
13	Transportation - Existing Rates	20,711	20,734	-	20,734	23	- Sect 7-TAB 7.2, Schedule 11
14	- Increase / (Decrease)	-		-	-	-	- Sect 7-TAB 7.2, Schedule 14
15							
16	FEVI Revenue (Surplus) / Deficit	(20,970)	-	4	4	20,974	- Sect 7-TAB 7.2, Schedule 14
17	**Total Revenue**	172,676	195,087	4	195,091	22,415	
18							
19	Cost of Gas Sold (Including Gas Lost)	66,773	74,337	-	74,337	7,564	- Sect 7-TAB 7.2, Schedule 13
20	Royalty Credit	(17,283)	-	-	-	17,283	
21	GCVA Amortization	3,282	(8,124)	-	(8,124)	(11,406)	
22	GCVA Additions	11,053	-	-	-	(11,053)	
23							
24	**Gross Margin**	108,851	128,874	4	128,878	20,027	
25							
26	Operation and Maintenance	28,136	30,303	-	30,303	2,167	- Sect 7-TAB 7.2, Schedule 21
27	Transportation Costs	4,480	4,483	-	4,483	3	
28	Property and Sundry Taxes	9,293	9,895	-	9,895	602	- Sect 7-TAB 7.2, Schedule 25
29	Depreciation and Amortization	24,962	35,896	-	35,896	10,934	- Sect 7-TAB 7.2, Schedule 28
30	NSP Provisions	(1,400)	-	-	-	1,400	
31	Interest on Subordinated Debt	-	-	-	-	-	
32	Other Operating Revenue	(7,629)	(12,651)	-	(12,651)	(5,022)	- Sect 7-TAB 7.2, Schedule 19
33	Sub-total	57,842	67,926	-	67,926	10,084	
34	Utility Income Before Income Taxes	51,009	60,948	4	60,952	9,943	
35							
36	Income Taxes	3,655	3,877	1	3,878	223	- Sect 7-TAB 7.2, Schedule 31
37							
38	**EARNED RETURN after VINGPA Adjustment**	$ 47,354	57,071	$ 3	$ 57,074	$ 9,720	- Sect 7-TAB 7.2, Schedule 31
39	VINGPA Adjustment (ends December 31, 2011)	(1,867)	-	-	-	1,867	
40	**EARNED RETURN before VINGPA Adjustment**	$ 49,221	$ 57,071	$ 3	$ 57,074	$ 7,853	- Sect 7-TAB 7.2, Schedule 80
41							
42							
43	**UTILITY RATE BASE**	$ 677,048	$ 787,864	$ -	$ 787,864	$ 110,816	- Sect 7-TAB 7.2, Schedule 40
44							
45	**RATE OF RETURN ON UTILITY RATE BASE before VINGPA Adjustment**	7.27%	7.24%		7.24%	-0.03%	- Sect 7-TAB 7.2, Schedule 80

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 ---- Cost of Service Rates ---- Existing 2011 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	11,774	11,860	-	11,860	86	- Sect 7-TAB 7.2, Schedule 9
3	Transportation	22,295	22,295	-	22,295	-	- Sect 7-TAB 7.2, Schedule 9
4		34,069	34,155	-	34,155	86	
5							
6	Average Rate per GJ						
7	Sales	$ 14.809	$ 14.832	$ -	$ 16.303	$ 1.494	
8	Transportation	$ 0.930	$ 0.930	$ -	$ 0.930	$ -	
9	Average	$ 5.726	$ 5.757	$ -	$ 6.268	$ 0.542	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 174,353	$ 175,913	$ -	$ 175,913	$ 1,560	- Sect 7-TAB 7.2, Schedule 12
13	Transportation - Existing Rates	20,734	20,734	-	20,734	-	- Sect 7-TAB 7.2, Schedule 12
14	- Increase / (Decrease)	-		-	-	-	- Sect 7-TAB 7.2, Schedule 16
15							
16	FEVI Revenue (Surplus) / Deficit	4	-	17,440	17,440	17,436	- Sect 7-TAB 7.2, Schedule 16
17	**Total Revenue**	195,091	196,647	17,440	214,087	18,996	
18							
19	Cost of Gas Sold (Including Gas Lost)	74,337	76,399	-	76,399	2,062	- Sect 7-TAB 7.2, Schedule 13
20	Royalty Credit	-	-	-	-	-	
21	GCVA Amortization	(8,124)	-	-	-	8,124	
22	GCVA Additions	-	-	-	-	-	
23							
24	**Gross Margin**	128,878	120,248	17,440	137,688	8,810	
25							
26	Operation and Maintenance	30,303	30,515	-	30,515	212	- Sect 7-TAB 7.2, Schedule 21
27	Transportation Costs	4,483	4,494	-	4,494	11	
28	Property and Sundry Taxes	9,895	10,263	-	10,263	368	- Sect 7-TAB 7.2, Schedule 26
29	Depreciation and Amortization	35,896	37,334	-	37,334	1,438	- Sect 7-TAB 7.2, Schedule 29
30	NSP Provisions	-	-	-	-	-	
31	Interest on Subordinated Debt	-	-	-	-	-	
32	Other Operating Revenue	(12,651)	(12,662)	-	(12,662)	(11)	- Sect 7-TAB 7.2, Schedule 20
33	Sub-total	67,926	69,944	-	69,944	2,018	
34	Utility Income Before Income Taxes	60,952	50,304	17,440	67,744	6,792	
35							
36	Income Taxes	3,878	3,082	4,358	7,440	3,562	- Sect 7-TAB 7.2, Schedule 32
37							
38	**EARNED RETURN after VINGPA Adjustment**	$ 57,074	47,222	$ 13,082	$ 60,304	$ 3,230	- Sect 7-TAB 7.2, Schedule 32
39	VINGPA Adjustment (ends December 31, 2011)	-	-	-	-	-	
40	**EARNED RETURN before VINGPA Adjustment**	$ 57,074	$ 47,222	$ 13,082	$ 60,304	$ 3,230	- Sect 7-TAB 7.2, Schedule 81
41							
42							
43	**UTILITY RATE BASE**	$ 787,864	$ 813,816	$ 262	$ 814,078	$ 26,214	- Sect 7-TAB 7.2, Schedule 41
44							
45	**RATE OF RETURN ON UTILITY RATE BASE before VINGPA Adjustment**	7.24%	5.80%		7.41%	0.16%	- Sect 7-TAB 7.2, Schedule 81

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Projected Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	RGS	4,547.8	5,015.3	4,629.5	-	4,629.5	(385.8)	
3	LCS 2	1,288.7	1,396.8	1,314.3		1,314.3	(82.5)	
4	LCS 3	1,982.1	2,417.2	1,977.5		1,977.5	(439.7)	
5								
6	Residential & Commercial	11,256.7	12,179.7	11,522.3	-	11,522.3	(657.4)	
7								
8	HLF	112.4	120.5	112.2		112.2	(8.3)	
9	ILF	122.3	132.4	61.1		61.1	(71.3)	
10								
11	Total Sales	11,491.4	12,432.6	11,695.6	-	11,695.6	(737.0)	- Sect 7-TAB 7.2, Schedule 4
12								
13	**TRANSPORTATION SERVICE**							
14	BC Hydro and ICP	12,941.0	17,945.0		16,425.6	16,425.6	(1,519.4)	
15	VIGJV	5,447.7	2,920.0		2,919.6	2,919.6	(0.4)	
16	FEW	753.2	729.9		2,565.6	2,565.6	1,835.7	
17	Squamish	384.5	422.3		384.6	384.6	(37.7)	
18	Total Transportation Service	19,526.3	22,017.2	-	22,295.4	22,295.4	278.2	- Sect 7-TAB 7.2, Schedule 4
19								
20	**TOTAL SALES AND TRANSPORTATION SERVICES**	31,017.7	34,450.0	11,695.6	22,295.4	33,991.0	(458.8)	- Sect 7-TAB 7.2, Schedule 4

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars	2011 PROJECTED	2012 Forecast Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	RGS	4,629.5	4,575.9	-	4,575.9	(53.6)	
3	LCS 2	1,314.3	1,339.8		1,339.8	25.5	
4	LCS 3	1,977.5	1,977.5		1,977.5	-	
5							
6	Residential & Commercial	11,522.3	11,600.6	-	11,600.6	78.3	
7							
8	HLF	112.2	112.2		112.2	-	
9	ILF	61.1	61.1		61.1	-	
10							
11	Total Sales	11,695.6	11,773.9	-	11,773.9	78.3	- Sect 7-TAB 7.2, Schedule 5
12							
13	**TRANSPORTATION SERVICE**						
14	BC Hydro and ICP	16,425.6		16,425.6	16,425.6	-	
15	VIGJV	2,919.6		2,919.6	2,919.6	-	
16	FEW	2,565.6		2,565.6	2,565.6	-	
17	Squamish	384.6		384.6	384.6	-	
18	Total Transportation Service	22,295.4	-	22,295.4	22,295.4	-	- Sect 7-TAB 7.2, Schedule 5
19							
20	**TOTAL SALES AND TRANSPORTATION SERVICES**	33,991.0	11,773.9	22,295.4	34,069.3	78.3	- Sect 7-TAB 7.2, Schedule 5

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 FORECAST	2013 Forecast Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	RGS	4,575.9	4,528.0	-	4,528.0	(47.9)	
3	LCS 2	1,339.8	1,365.5		1,365.5	25.7	
4	LCS 3	1,977.5	1,977.5		1,977.5	-	
5							
6	Residential & Commercial	11,600.6	11,687.0	-	11,687.0	86.4	
7							
8	HLF	112.2	112.2		112.2	-	
9	ILF	61.1	61.1		61.1	-	
10							
11	Total Sales	11,773.9	11,860.3	-	11,860.3	86.4	- Sect 7-TAB 7.2, Schedule 6
12							
13	**TRANSPORTATION SERVICE**						
14	BC Hydro and ICP	16,425.6		16,425.6	16,425.6	-	
15	VIGJV	2,919.6		2,919.6	2,919.6	-	
16	FEW	2,565.6		2,565.6	2,565.6	-	
17	Squamish	384.6		384.6	384.6	-	
18	Total Transportation Service	22,295.4	-	22,295.4	22,295.4	-	- Sect 7-TAB 7.2, Schedule 6
19							
20	**TOTAL SALES AND TRANSPORTATION SERVICES**	34,069.3	11,860.3	22,295.4	34,155.7	86.4	- Sect 7-TAB 7.2, Schedule 6

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	**SALES**							
2	RGS	$ 76,335	$ 83,340	$ 77,516	$ -	$ 77,516	$ (5,824)	
3	LCS 2	16,393	17,814	16,567		16,567	(1,247)	
4	LCS 3	24,098	29,337	24,093		24,093	(5,244)	
5	Residential & Commercial	167,321	179,703	170,917	-	170,917	(8,786)	
6								
7	HLF	1,094	1,241	1,281	-	1,281	40	
8	ILF	1,374	1,459	737		737	(722)	
9		2,468	2,699	2,018	-	2,018	(681)	
10								
11	Total Sales	169,789	182,402	172,935	-	172,935	(9,467)	- Sect 7-TAB 7.2, Schedule 4
12								
13	**Transportation Service**							
14	BC Hydro and ICP	15,676	14,894		14,903	14,903	9	
15	VIGJV	5,111	2,776		2,809	2,809	33	
16	FEW	2,430	2,386		2,585	2,585	199	
17	Squamish	404	443		414	414	(29)	
18	Total Transportation Service	23,621	20,500	-	20,711	20,711	211	
19								
20	TOTAL SALES AND TRANSPORTATION SERVICES	$ 193,410	$ 202,902	$ 172,935	$ 20,711	$ 193,646	$ (9,256)	- Sect 7-TAB 7.2, Schedule 4

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	2012 Gas Sales Revenue At Existing 2011 Rates: Bypass and Special Rates	2012 Gas Sales Revenue At Existing 2011 Rates: Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	RGS	$ 77,516	$ 77,040	$ -	$ 77,040	$ (476)	
3	LCS 2	16,567	16,881		16,881	314	
4	LCS 3	24,093	24,093		24,093	-	
5	Residential & Commercial	170,917	172,335	-	172,335	1,418	
6							
7	HLF	1,281	1,281	-	1,281	-	
8	ILF	737	737		737	-	
9		2,018	2,018	-	2,018	-	
10							
11	Total Sales	172,935	174,353	-	174,353	1,418	- Sect 7-TAB 7.2, Schedule 5
12							
13	**Transportation Service**						
14	BC Hydro and ICP	14,903		14,903	14,903	-	
15	VIGJV	2,809		2,832	2,832	23	
16	FEW	2,585		2,585	2,585	-	
17	Squamish	414		414	414	-	
18	Total Transportation Service	20,711	-	20,734	20,734	23	
19							- Sect 7-TAB 7.2, Schedule 5
20	TOTAL SALES AND TRANSPORTATION SERVICES	$ 193,646	$ 174,353	$ 20,734	$ 195,087	$ 1,441	- Sect 7-TAB 7.2, Schedule 5

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	RGS	$ 77,040	$ 76,657	$ -	$ 76,657	$ (383)	
3	LCS 2	16,881	17,200		17,200	319	
4	LCS 3	24,093	24,093		24,093	-	
5	Residential & Commercial	172,335	173,895	-	173,895	1,560	
6							
7	HLF	1,281	1,281	-	1,281	-	
8	ILF	737	737		737	-	
9		2,018	2,018	-	2,018	-	
10							
11	Total Sales	174,353	175,913	-	175,913	1,560	- Sect 7-TAB 7.2, Schedule 6
12							
13	**Transportation Service**						
14	BC Hydro and ICP	14,903		14,903	14,903	-	
15	VIGJV	2,832		2,832	2,832	-	
16	FEW	2,585		2,585	2,585	-	
17	Squamish	414		414	414	-	
18	Total Transportation Service	20,734	-	20,734	20,734	-	
19							- Sect 7-TAB 7.2, Schedule 6
20	TOTAL SALES AND TRANSPORTATION SERVICES	$ 195,087	$ 175,913	$ 20,734	$ 196,647	$ 1,560	- Sect 7-TAB 7.2, Schedule 6

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011 Gas Costs		2012 Gas Costs		2013 Gas Costs	
Line No.	Particulars	Non-Bypass Sales & Transp	Total	Non-Bypass Sales & Transp	Total	Non-Bypass Sales & Transp	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	RGS	26,431	$ 26,431	$ 28,890	$ 28,890	29,167	$ 29,167
3	LCS 2	7,504	7,504	8,459	8,459	8,796	8,796
4	LCS 3	11,290	11,290	12,485	12,485	12,738	12,738
5							
6	Residential & Commercial	65,783	65,783	73,242	73,242	75,282	75,282
7							
8	HLF	641	641	709	709	723	723
9	ILF	349	349	386	386	394	394
10							
11		990	990	1,095	1,095	1,117	1,117
12							
13	Total Sales	66,773	66,773	74,337	74,337	76,399	76,399
14							
15	TOTAL SALES AND TRANSPORTATION SERVICES	$ 66,773	$ 66,773	$ 74,337	$ 74,337	$ 76,399	$ 76,399
16							
17	Cross Reference	- Sect 7-TAB 7.2, Schedule 4		- Sect 7-TAB 7.2, Schedule 5		- Sect 7-TAB 7.2, Schedule 6	

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Effective Increase / (Decrease) 0.00% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000s)	Average Number of Customers	Revenue ---- Cost of Service Rates ---- Average $/GJ	Revenue ---- Cost of Service Rates ---- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	RGS	4,575.9	$ 16.641	$ 77,040	$ 10.401	$ 48,150	$ 0.001	$ 4	94,171	$ 16.642	$ 77,044
4	LCS 2	1,339.8	12.844	16,881	6.408	8,422	-	-	517	12.844	16,881
5	LCS 3	1,977.5	12.184	24,093	5.870	11,607	-	-	121	12.184	24,093
6	Residential & Commercial	11,600.6		172,335		99,095		4	103,736		172,339
7											
8	HLF	112.2	11.417	1,281	5.098	572	-	-	8	11.417	1,281
9	ILF	61.1	12.062	737	5.745	351	-	-	6	12.062	737
10											
11	Total Sales	11,773.9		174,353		100,018		4	103,750		174,357
12											
13	Total Transportation Service	-		-		-		-	-		-
14											
15	Total Non-Bypass Sales & Transportation Service	11,773.9		$ 174,353		$ 100,018		$ 4	103,750		$ 174,357
16											
17	Cross Reference	- Sect 7-TAB 7.2, Schedule 8		- Sect 7-TAB 7.2, Schedule 11				- Sect 7-TAB 7.2, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 0.00% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Cost of Service Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	BC Hydro and ICP	16,425.6	0.907	14,903	0.907	14,903	-	-	1	0.907	14,903
4	VIGJV	2,919.6	0.970	2,832	0.970	2,832	-	-	1	0.970	2,832
5	FEW	2,565.6	1.008	2,585	1.008	2,585	-	-	1	1.008	2,585
6	Squamish	384.6	1.076	414	1.076	414	-	-	1	1.076	414
7	Total Bypass and Spec. Rates T-Svc	22,295.4		20,734		20,734		-	4		20,734
8											
9	TOTAL NON-BYPASS AND BYPASS SALES AND										
10	TRANSPORTATION SERVICE	34,069.3		$ 195,087		$ 120,752		$ 4	103,754		$ 195,091
11											
12	Cross Reference	- Sect 7-TAB 7.2, Schedule 8		- Sect 7-TAB 7.2, Schedule 11				- Sect 7-TAB 7.2, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Effective Increase / (Decrease) 17.53% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Cost of Service Rates ---- Average $/GJ	Revenue ---- Cost of Service Rates ---- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	RGS	4,528.0	$ 16.558	$ 76,657	$ 10.258	$ 47,489	$ 1.798	$ 8,322	96,682	$ 18.356	$ 84,979
4	LCS 2	1,365.5	13.087	17,200	6.394	8,404	1.121	1,473	517	14.208	18,673
5	LCS 3	1,977.5	12.184	24,093	5.742	11,354	1.006	1,990	121	13.190	26,083
6	Residential & Commercial	11,687.0		173,895		98,612		17,282	106,342		191,177
7											
8	HLF	112.2	11.417	1,281	4.964	557	0.873	98	8	12.290	1,379
9	ILF	61.1	12.062	737	5.630	344	0.982	60	6	13.044	797
10											
11	Total Sales	11,860.3		175,913		99,513		17,440	106,356		193,353
12											
13	Total Transportation Service	-		-		-		-	-		-
14											
15	Total Non-Bypass Sales & Transportation Service	11,860.3		$ 175,913		$ 99,513		$ 17,440	106,356		$ 193,353
16											
17	Cross Reference	- Sect 7-TAB 7.2, Schedule 9		- Sect 7-TAB 7.2, Schedule 12				- Sect 7-TAB 7.2, Schedule 3			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 17.53% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ---- Cost of Service Rates ---- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	BC Hydro and ICP	16,425.6	0.907	14,903	0.907	14,903	-	-	1	0.9070	14,903
4	VIGJV	2,919.6	0.970	2,832	0.970	2,832	-	-	1	0.9700	2,832
5	FEW	2,565.6	1.008	2,585	1.008	2,585	-	-	1	1.0080	2,585
6	Squamish	384.6	1.076	414	1.076	414	-	-	1	1.0760	414
7	Total Bypass and Spec. Rates T-Svc	22,295.4		20,734		20,734		-	4		20,734
8											
9	TOTAL NON-BYPASS AND BYPASS SALES AND										
10	TRANSPORTATION SERVICE	34,155.7		$ 196,647		$ 120,247		$ 17,440	106,360		$ 214,087
11											
12	Cross Reference	- Sect 7-TAB 7.2, Schedule 9		- Sect 7-TAB 7.2, Schedule 12				- Sect 7-TAB 7.2, Schedule 3			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 295	$ 345	$ 222	$ (123)	- Sect 7-TAB 7.2, Schedule 76
4						
5	Connection Charge	391	380	389	9	- Sect 7-TAB 7.2, Schedule 76
6						
7	NSF Returned Cheque Charges	5	5	3	(2)	- Sect 7-TAB 7.2, Schedule 76
8						
9	Other Recoveries	(3)	2	-	(2)	- Sect 7-TAB 7.2, Schedule 76
10						
11	Total Other Utility Revenue	690	732	614	(118)	
12						
13	**Miscellaneous Revenue**					
14						
15	LNG Mitigation Revenue from FEI	-	9,020	7,015	(2,005)	- Sect 7-TAB 7.2, Schedule 76
16						
17						
18	Total Miscellaneous	-	9,020	7,015	(2,005)	
19						
20	**Total Other Operating Revenue**	$ 690	$ 9,752	$ 7,629	$ (2,123)	- Sect 7-TAB 7.2, Schedule 4

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 222	$ 223	$ 1	- Sect 7-TAB 7.2, Schedule 76
4					
5	Connection Charge	389	399	10	- Sect 7-TAB 7.2, Schedule 76
6					
7	NSF Returned Cheque Charges	3	3	-	- Sect 7-TAB 7.2, Schedule 76
8					
9	Other Recoveries	-	-	-	- Sect 7-TAB 7.2, Schedule 76
10					
11	Total Other Utility Revenue	614	625	11	
12					
13	**Miscellaneous Revenue**				
14					
15	LNG Mitigation Revenue from FEI	7,015	12,026	5,011	- Sect 7-TAB 7.2, Schedule 76
16					
17					
18	Total Miscellaneous	7,015	12,026	5,011	
19					
20	**Total Other Operating Revenue**	$ 7,629	$ 12,651	$ 5,022	- Sect 7-TAB 7.2, Schedule 5

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 223	$ 224	$1	- Sect 7-TAB 7.2, Schedule 76
4					
5	Connection Charge	399	409	10	- Sect 7-TAB 7.2, Schedule 76
6					
7	NSF Returned Cheque Charges	3	3	-	- Sect 7-TAB 7.2, Schedule 76
8					
9	Other Recoveries	-	-	-	- Sect 7-TAB 7.2, Schedule 76
10					
11	Total Other Utility Revenue	625	636	11	
12					
13	**Miscellaneous Revenue**				
14					
15	LNG Mitigation Revenue from FEI	12,026	12,026	-	- Sect 7-TAB 7.2, Schedule 76
16					
17					
18	Total Miscellaneous	12,026	12,026	-	
19					
20	**Total Other Operating Revenue**	$ 12,651	$ 12,662	$ 11	- Sect 7-TAB 7.2, Schedule 6

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 3,570	$ 3,868	$ 4,034	$ 3,305	$ 3,307	
2	COPE Costs	248	110	115	105	109	
3	IBEW Costs	4,644	5,451	4,862	5,796	6,199	
4							
5	**Labour Costs**	**8,462**	**9,429**	**9,011**	**9,207**	**9,615**	
6							
7	Vehicle Costs	606	722	672	778	786	
8	Employee Expenses	568	587	628	596	611	
9	Materials and Supplies	1,122	1,395	1,073	1,090	1,099	
10	Computer Costs	529	231	234	198	181	
11	Fees and Administration Costs [1]	11,465	11,911	12,145	14,507	14,556	
12	Contractor Costs [1]	6,205	7,125	7,480	7,588	8,294	
13	Facilities	2,047	2,416	2,446	2,565	1,654	
14	Recoveries & Revenue	(1,153)	(1,115)	(1,071)	(1,293)	(1,314)	
15							
16	**Non-Labour Costs**	**21,390**	**23,273**	**23,606**	**26,030**	**25,867**	
17							
18							
19	**Total Gross O&M Expenses**	**29,852**	**32,702**	**32,617**	**35,236**	**35,482**	
20							
21	Add: PST Savings	-	-	85	0	(0)	
22	Less: O&M Difference from Allowed	1,379	-	-	-	-	
23	Less: Capitalized Overhead	(4,372)	(4,567)	(4,566)	(4,933)	(4,968)	
24							- Sect 7-TAB 7.2, Schedule 4
25	**Total O&M Expenses**	**$ 26,859**	**$ 28,136**	**$ 28,136**	**$ 30,303**	**$ 30,515**	- Sect 7-TAB 7.2, Schedule 5
26							- Sect 7-TAB 7.2, Schedule 6
27	[1] 2012 and 2013 reflect customer service costs previously contracted						

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 1,827	$ 1,951	$ 1,921	$ 2,039	$ 2,096	
2								
3	Operation Centre - Distribution	100-21	443	526	474	517	539	
4	Asset Management - Distribution	100-22	-	-	-	-	-	
5	Preventative Maintenance - Distribution	100-23	193	172	93	174	221	
6	Distribution Operations - General	100-24	1,069	795	974	1,238	1,290	
7	Meter Exchange	100-25	-	-	-	-	-	
8	Emergency Management	100-26	820	1,266	1,002	894	932	
9	Distribution Operations Total	100-20	2,525	2,759	2,544	2,823	2,982	
10								
11	Distribution Corrective - Meters	100-31	301	169	193	293	306	
12	Distribution Corrective - Propane	100-32	-	-	-	-	-	
13	Distribution Corrective - Leak Repair	100-33	86	139	123	86	89	
14	Distribution Corrective - Stations	100-34	13	40	23	13	13	
15	Distribution Corrective - General	100-35	68	75	71	128	461	
16	Distribution Maintenance Total	100-30	467	422	410	520	869	
17								
18	**Distribution Total**	**100**	**4,819**	**5,132**	**4,875**	**5,382**	**5,947**	
19								
20	Transmission Supervision	200-11	-	-	622	642	662	
21								
22	Pipeline Operation	200-21	1,316	1,346	838	901	1,004	
23	Right of Way	200-22	114	175	159	237	271	
24	Compression	200-23	919	1,004	1,087	1,152	1,191	
25	Gas Control	200-24	-	-	-	-	-	
26	Transmission Pipeline Integrity Project (TPIP)	200-25	-	-	-	-	-	
27	Transmission Operations Total	200-20	2,350	2,525	2,085	2,290	2,466	
28								
29	Pipeline - Maintenance	200-31	490	610	636	509	534	
30	Compression - Maintenance	200-32	716	671	284	373	383	
31	TPIP - Maintenance	200-33	-	-	1,038	1,026	1,031	
32	Transmission Maintenance Total	200-30	1,206	1,281	1,958	1,909	1,948	
33								
34	**Transmission Total**	**200**	**3,555**	**3,806**	**4,665**	**4,840**	**5,076**	
35								
36	LNG Plant Operations	300-11	438	1,685	1,149	1,658	1,738	
37	LNG Plant Maintenance	300-21	-	-	380	357	349	
38								
39	**LNG Plant Total**	**300**	**438**	**1,685**	**1,529**	**2,015**	**2,087**	
40								
41	Measurement Operations	400-11	459	527	-	-	-	
42	Measurement Maintenance	400-21	457	603	405	359	370	
43								
44	**Measurement Total**	**400**	**917**	**1,130**	**405**	**359**	**370**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Facilities Management	500-10	$ 1,460	$ 1,596	$ 1,613	$ 1,463	$ 539	
2	Shops & Stores	500-20	-	-	-	-	-	
3	Operations Engineering	500-30	750	310	293	314	311	
4	Property Services	500-40	-	-	-	-	-	
5	System Integrity	500-50	119	210	210	208	209	
6	Environmental Health & Safety	500-60	-	-	-	-	-	
7	Operations Governance	500-70	-	-	-	-	-	
8	Energy Supply & Resource Development	500-80	-	-	-	-	-	
9	**General Operations Total**	**500**	**2,329**	**2,116**	**2,116**	**1,986**	**1,059**	
10								
11	Energy Efficiency	600-10	-	-	-	-	-	
12	Marketing - Supervision	600-20	-	-	-	-	-	
13	Corporate & Marketing Communications	600-30	137	-	64	87	87	
14	Marketing Planning & Development	600-40	-	-	-	-	-	
15	**Marketing Total**	**600**	**137**	**-**	**64**	**87**	**87**	
16								
17	Customer Care - Supervision	700-10	-	-	-	-	-	
18	Customer Contact	700-20	4,891	5,480	5,395	5,174	5,517	
19	Bad Debt Management and Administration	700-30	312	276	238	197	205	
20	Customer Management & Sales	700-40	1,095	1,168	1,163	1,200	1,236	
21	**Customer Care Total**	**700**	**6,298**	**6,923**	**6,797**	**6,571**	**6,957**	
22								
23	Business & IT Services - Supervision	800-10	-	-	-	-	-	
24	Application Management	800-20	387	438	421	422	426	
25	Infrastructure Management	800-30	-	-	-	-	-	
26	Procurement Services	800-40	-	-	-	-	-	
27	**Business & IT Services Total**	**800**	**387**	**438**	**421**	**422**	**426**	
28								
29	Administration & General	900-11	232	415	673	631	631	
30	Insurance	900-12	861	902	930	1,040	1,090	
31	Finance and Regulatory Affairs	900-13	381	384	383	493	493	
32	Shared Services Agreement	900-14	8,326	8,644	8,637	10,780	10,719	
33	Corporate Administration Total	900-10	9,801	10,345	10,623	12,944	12,933	
34	Forecasting	900-20	-	-	-	-	-	
35	Public Affairs	900-30	234	270	300	457	458	
36	Business Development	900-40	-	-	-	-	-	
37	Human Resources	900-50	-	-	-	-	-	
38	Other Post Employment Benefits (OPEB)	900-60	937	858	824	174	82	
39	**Administration & General Total**	**900**	**10,972**	**11,473**	**11,747**	**13,575**	**13,473**	
40								
41	**Total Gross O&M Expenses**		**29,852**	**32,702**	**32,617**	**35,236**	**35,482**	
42								
43	Add: PST Savings		-	-	85	0	(0)	
44	Less: O&M Difference from Allowed		1,379	-	-	-	-	
45	Less: Capitalized Overhead		(4,372)	(4,567)	(4,566)	(4,933)	(4,968)	
46								- Sect 7-TAB 7.2, Schedule 4
47	**Total O&M Expenses**		**$ 26,859**	**$ 28,136**	**$ 28,136**	**$ 30,303**	**$ 30,515**	- Sect 7-TAB 7.2, Schedule 5
48								- Sect 7-TAB 7.2, Schedule 6

FORTISBC ENERGY (Vancouver Island) INC. May 4, 2011 Section 7
TAB 7.2
Schedule 24

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Total Expenses	2011 PROJECTED Cost of Service Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 1,643	$ 1,655	$ 1,684	$ 1,684	$ 29	
4							
5	General, School and Other	7,396	7,909	7,609	7,609	(300)	
6							
7	Total	$ 9,039	$ 9,564	$ 9,293	$ 9,293	$ (271)	- Sect 7-TAB 7.2, Schedule 4

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Total Expenses	2012 Cost of Service Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 1,684	$ 1,549	$ 1,549	$ (135)	
4						
5	General, School and Other	7,609	8,346	8,346	737	
6						
7	Total	$ 9,293	$ 9,895	$ 9,895	$ 602	- Sect 7-TAB 7.2, Schedule 5

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Total Expenses	2013 Cost of Service Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 1,549	$ 1,549	$ 1,549	$ -	
4						
5	General, School and Other	8,346	8,714	8,714	368	
6						
7	Total	$ 9,895	$ 10,263	$ 10,263	$ 368	- Sect 7-TAB 7.2, Schedule 6

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 25,975	$ 30,409	$ 29,458	$ (951)	- Sect 7-TAB 7.2, Schedule 54
4						
5	Less: Amortization of Contributions in Aid of Construction	(4,420)	(4,423)	(4,427)	(4)	- Sect 7-TAB 7.2, Schedule 63
6		21,554	25,986	25,031	(955)	
7						
8	Add: Removal Cost Provision	343	344	344	-	
9		21,897	26,330	25,375	(955)	- Sect 7-TAB 7.2, Schedule 33
10						
11	**Amortization Expense**					
12						
13	Amortization of Deferred Charges	$ (6,209)	$ 727	$ 4,350	$ 3,623	- Sect 7-TAB 7.2, Schedule 67
14	Amortization of 2009 Revenue Surplus	(1,481)	(1,481)	(1,481)	-	
15	Less: GCVA Amortization	-	-	(3,282)	(3,282)	
16		(7,690)	(754)	(413)	341	
17						
18	TOTAL	14,207	25,577	24,962	$ (615)	- Sect 7-TAB 7.2, Schedule 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 29,458	$ 34,043	$ 4,585	- Sect 7-TAB 7.2, Schedule 57
4					
5	Less: Amortization of Contributions in Aid of Construction	(4,427)	(4,178)	249	- Sect 7-TAB 7.2, Schedule 64
6		25,031	29,865	4,834	
7					
8	Add: Removal Cost Provision	344	3,915	3,571	
9		25,375	33,780	8,405	- Sect 7-TAB 7.2, Schedule 34
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ 4,350	$ (6,008)	$ (10,358)	- Sect 7-TAB 7.2, Schedule 69
14	Amortization of 2009 Revenue Surplus	(1,481)	-	1,481	
15	Less: GCVA Amortization	(3,282)	8,124	11,406	
16		(413)	2,116	2,529	
17					
18	TOTAL	$ 24,962	$ 35,896	$ 10,934	- Sect 7-TAB 7.2, Schedule 5

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 34,043	$ 35,165	$ 1,122	- Sect 7-TAB 7.2, Schedule 60
4					
5	Less: Amortization of Contributions in Aid of Construction	(4,178)	(4,187)	(9)	- Sect 7-TAB 7.2, Schedule 65
6		29,865	30,978	1,113	
7					
8	Add: Removal Cost Provision	3,915	4,046	131	
9		33,780	35,024	1,244	- Sect 7-TAB 7.2, Schedule 35
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ (6,008)	$ 2,310	$ 8,318	- Sect 7-TAB 7.2, Schedule 71
14	Amortization of 2009 Revenue Surplus	-	-	-	
15	Less: GCVA Amortization	8,124	-	(8,124)	
16		2,116	2,310	194	
17					
18	TOTAL	$ 35,896	$ 37,334	$ 1,438	- Sect 7-TAB 7.2, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED ---- Cost of Service Rates ---- Existing Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN after VINGPA Adjustment	$ 34,995	$ 53,419	$ 62,769	$ (15,415)	$ 47,354	$ (6,065)	- Sect 7-TAB 7.2, Schedule 4
3	Deduct - Interest on Debt	(14,956)	(26,126)	(22,160)	7	(22,153)	3,973	- Sect 7-TAB 7.2, Schedule 79
4	Accounting Income After Tax	20,039	27,293	40,609	(15,408)	25,201	(2,092)	
5	Net Additions (Deductions)	(15,666)	(17,174)	(15,063)	-	(15,063)	2,111	- Sect 7-TAB 7.2, Schedule 33
6	Adjusted Taxable Income After Tax	$ 4,374	$ 10,119	25,546	$ (15,408)	$ 10,138	$ 19	
7								
8	Current Income Tax Rate	28.50%	26.50%	26.50%	26.50%	26.50%	0.00%	
9	1 - Current Income Tax Rate	71.50%	73.50%	73.50%	73.50%	73.50%	0.00%	
10								
11								
12	Taxable Income	$ 6,117	$ 13,767	$ 34,756	$ (20,963)	$ 13,793	$ 26	
13								
14								
15	Income Tax - Current	$ 1,743	$ 3,648	$ 9,210	$ (5,555)	$ 3,655	$ 7	
16	Previous Year Adjustment	(78)	-		-		-	
17	Income Tax - FIT Opening Adjustment	-	-		-		-	
18								
19	**Total Income Tax**	$ 1,665	$ 3,648	$ 9,210	$ (5,555)	$ 3,655	$ 7	- Sect 7-TAB 7.2, Schedule 4
20								

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

			2012				
			---- Cost of Service Rates ----				
Line No.	Particulars	2011 PROJECTED	Existing Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN after VINGPA Adjustment	$ 47,354	$ 57,071	$ 3	$ 57,074	$ 9,720	- Sect 7-TAB 7.2, Schedule 5
3	Deduct - Interest on Debt	(22,153)	(25,559)	-	(25,559)	(3,406)	- Sect 7-TAB 7.2, Schedule 80
4	Accounting Income After Tax	25,201	31,512	3	31,515	6,314	
5	Net Additions (Deductions)	(15,063)	(19,880)	-	(19,880)	(4,817)	- Sect 7-TAB 7.2, Schedule 34
6	Adjusted Taxable Income After Tax	$ 10,138	$ 11,632	$ 3	$ 11,635	$ 1,497	
7							
8	Current Income Tax Rate	26.50%	25.00%	25.00%	25.00%	-1.50%	
9	1 - Current Income Tax Rate	73.50%	75.00%	75.00%	75.00%	1.50%	
10							
11							
12	Taxable Income	$ 13,793	$ 15,509	$ 4	$ 15,513	$ 1,720	
13							
14							
15	Income Tax - Current	$ 3,655	$ 3,877	$ 1	$ 3,878	$ 223	
16	Previous Year Adjustment	-		-		-	
17	Income Tax - FIT Opening Adjustment	-		-		-	
18							
19	**Total Income Tax**	$ 3,655	$ 3,877	$ 1	$ 3,878	$ 223	- Sect 7-TAB 7.2, Schedule 5
20							

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 ---- Cost of Service Rates ---- Existing Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN after VINGPA Adjustment	$ 57,074	$ 47,222	$ 13,082	$ 60,304	$ 3,230	- Sect 7-TAB 7.2, Schedule 6
3	Deduct - Interest on Debt	(25,559)	(27,733)	(8)	(27,741)	(2,182)	- Sect 7-TAB 7.2, Schedule 81
4	Accounting Income After Tax	31,515	19,489	13,074	32,563	1,048	
5	Net Additions (Deductions)	(19,880)	(10,243)	-	(10,243)	9,637	- Sect 7-TAB 7.2, Schedule 35
6	Adjusted Taxable Income After Tax	$ 11,635	$ 9,246	$ 13,074	$ 22,320	$ 10,685	
7							
8	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
9	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
10							
11							
12	Taxable Income	$ 15,513	$ 12,328	$ 17,432	$ 29,760	$ 14,247	
13							
14							
15	Income Tax - Current	$ 3,878	$ 3,082	$ 4,358	$ 7,440	$ 3,562	
16	Previous Year Adjustment	-		-		-	
17	Income Tax - FIT Opening Adjustment	-		-		-	
18							
19	**Total Income Tax**	$ 3,878	$ 3,082	$ 4,358	$ 7,440	$ 3,562	- Sect 7-TAB 7.2, Schedule 6
20							

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 60	$ 68	$ 60	$ (8)	
3	Depreciation	21,897	26,330	25,375	(955)	- Sect 7-TAB 7.2, Schedule 27
4	Amortization of Debt Issue Expenses	328	42	418	376	
5	Pension Expense	1,408	1,484	1,023	(461)	
6	OPEB Expense	937	954	840	(114)	
7	Unpaid Remuneration	273	-	-	-	
8	IFRS Revenue Requirement Adjustment	1,400	-	(1,400)	(1,400)	
9	Variance in O&M expenses - Actual vs. Allowed	1,379	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	(6,209)	727	4,350	3,623	- Sect 7-TAB 7.2, Schedule 27
13	Amortization of Revenue Surplus / RSDA (FEVI)	(1,481)	(1,481)	(1,481)	-	- Sect 7-TAB 7.2, Schedule 27
14	Capital Cost Allowance	(29,166)	(38,743)	(36,646)	2,097	- Sect 7-TAB 7.2, Schedule 36
15	Cumulative Eligible Capital Allowance	(354)	(352)	(371)	(19)	
16	Debt Issue Costs	(823)	(862)	(666)	196	
17	Pension Contributions	(1,417)	(1,443)	(2,466)	(1,023)	
18	OPEB Contributions	(221)	(218)	(269)	(51)	
19	Overheads Capitalized Expensed for Tax Purposes	(2,811)	(2,936)	(2,936)	-	
20	Overhead Capitalization Rate Change	-	-	-	-	
21	Removal Costs	-	-	(344)	(344)	
22	Major Inspection Costs	(544)	(460)	(550)	(90)	
23	Taxable Capital Gain	21	60	-	(60)	
24						
25	TOTAL	$ (15,666)	$ (17,174)	$ (15,063)	$ 2,111	- Sect 7-TAB 7.2, Schedule 30

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 60	$ 60	$ -	
3	Depreciation	25,375	33,780	8,405	- Sect 7-TAB 7.2, Schedule 28
4	Amortization of Debt Issue Expenses	418	421	3	
5	Pension Expense	1,023	1,078	55	
6	OPEB Expense	840	361	(479)	
7	Unpaid Remuneration	-	-	-	
8	IFRS Revenue Requirement Adjustment	(1,400)	-	1,400	
9	Variance in O&M expenses - Actual vs. Allowed	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	4,350	(6,008)	(10,358)	- Sect 7-TAB 7.2, Schedule 28
13	Amortization of Revenue Surplus / RSDA (FEVI)	(1,481)	-	1,481	- Sect 7-TAB 7.2, Schedule 28
14	Capital Cost Allowance	(36,646)	(41,699)	(5,053)	- Sect 7-TAB 7.2, Schedule 37
15	Cumulative Eligible Capital Allowance	(371)	(345)	26	
16	Debt Issue Costs	(666)	(666)	-	
17	Pension Contributions	(2,466)	(2,495)	(29)	
18	OPEB Contributions	(269)	(289)	(20)	
19	Overheads Capitalized Expensed for Tax Purposes	(2,936)	(3,171)	(235)	
20	Overhead Capitalization Rate Change	-	-	-	
21	Removal Costs	(344)	(632)	(288)	
22	Major Inspection Costs	(550)	(275)	275	
23	Taxable Capital Gain	-	-	-	
24					
25	TOTAL	$ (15,063)	$ (19,880)	$ (4,817)	- Sect 7-TAB 7.2, Schedule 31

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 60	$ 60	$ -	
3	Depreciation	33,780	35,024	1,244	- Sect 7-TAB 7.2, Schedule 29
4	Amortization of Debt Issue Expenses	421	174	(247)	
5	Pension Expense	1,078	1,004	(74)	
6	OPEB Expense	361	385	24	
7	Unpaid Remuneration	-	-	-	
8	IFRS Revenue Requirement Adjustment	-	-	-	
9	Variance in O&M expenses - Actual vs. Allowed	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	(6,008)	2,310	8,318	- Sect 7-TAB 7.2, Schedule 29
13	Amortization of Revenue Surplus / RSDA (FEVI)	-	-	-	- Sect 7-TAB 7.2, Schedule 29
14	Capital Cost Allowance	(41,699)	(42,347)	(648)	- Sect 7-TAB 7.2, Schedule 38
15	Cumulative Eligible Capital Allowance	(345)	(325)	20	
16	Debt Issue Costs	(666)	(290)	376	
17	Pension Contributions	(2,495)	(2,094)	401	
18	OPEB Contributions	(289)	(303)	(14)	
19	Overheads Capitalized Expensed for Tax Purposes	(3,171)	(3,193)	(22)	
20	Overhead Capitalization Rate Change	-	-	-	
21	Removal Costs	(632)	(648)	(16)	
22	Major Inspection Costs	(275)	-	275	
23	Taxable Capital Gain	-	-	-	
24					
25	TOTAL	$ (19,880)	$ (10,243)	$ 9,637	- Sect 7-TAB 7.2, Schedule 32

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 286,004	$ 5,324	$ -	$ (11,654)	$ 279,674
2	1(b)	6%	8,634	(2,840)	6,715	(682)	11,827
3	2	6%	6,689	-	-	(401)	6,288
4	3	5%	136	-	-	(7)	129
5	6	10%	6	-	-	(1)	5
6	7	15%	16,295	-	2,587	(2,638)	16,244
7	8	20%	6,078	-	166	(1,232)	5,012
8	10	30%	1,700	-	1,207	(691)	2,216
9	12	100%	537	-	900	(987)	450
10	13	manual	157	-	40	(18)	179
11	14	manual	300	-	-	(25)	275
12	17	8%	784	-	(784)	-	-
13	38	30%	570	-	154	(194)	530
14	39	25%	-	-	-	-	-
15	45	45%	71	-	-	(32)	39
16	47	8%	74,324	(9,073)	96,878	(11,424)	150,705
17	49	8%	27,026	1,499	14,324	(3,070)	39,779
18	50 / 52	55% / 100%	337	-	600	(350)	587
19	51	6%	47,579	-	12,852	(3,240)	57,191
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 477,227	$ (5,090)	$ 135,639	$ (36,646)	$ 571,130
23							
24	Cross Reference					- Sect 7-TAB 7.2, Schedule 33	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	12/31/2011 UCC Balance	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 279,674	$ -	$ -	$ (11,187)	$ 268,487
2	1(b)	6%	11,827	-	8,906	(977)	19,756
3	2	6%	6,288	-	-	(377)	5,911
4	3	5%	129	-	-	(6)	123
5	6	10%	5	-	-	(1)	4
6	7	15%	16,244	(1)	4,106	(2,744)	17,605
7	8	20%	5,012	-	481	(1,050)	4,443
8	10	30%	2,216	-	2,913	(1,102)	4,027
9	12	100%	450	-	6,885	(3,893)	3,442
10	13	manual	179	-	393	(57)	515
11	14	manual	275	-	-	(25)	250
12	17	8%	-	-	-	-	-
13	38	30%	530	-	160	(183)	507
14	39	25%	-	-	-	-	-
15	45	45%	39	-	-	(18)	21
16	47	8%	150,705	-	788	(12,088)	139,405
17	49	8%	39,779	-	5,880	(3,418)	42,241
18	50	55%	587	-	1,157	(641)	1,103
19	51	6%	57,191	-	16,699	(3,932)	69,958
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 571,130	$ (1)	$ 48,368	$ (41,699)	$ 577,798
23							
24	Cross Reference					- Sect 7-TAB 7.2, Schedule 34	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 268,487	$ -	$ -	$ (10,739)	$ 257,748
2	1(b)	6%	19,756	-	361	(1,196)	18,921
3	2	6%	5,911	(1)	-	(355)	5,555
4	3	5%	123	(1)	-	(6)	116
5	6	10%	4	1	-	-	5
6	7	15%	17,605	-	2,133	(2,801)	16,937
7	8	20%	4,443	(1)	251	(914)	3,779
8	10	30%	4,027	-	3,431	(1,723)	5,735
9	12	100%	3,442	1	1,200	(4,043)	600
10	13	manual	515	-	30	(98)	447
11	14	manual	250	-	-	(25)	225
12	17	8%	-	-	-	-	-
13	38	30%	507	-	160	(176)	491
14	39	25%	-	-	-	-	-
15	45	45%	21	1	-	(10)	12
16	47	8%	139,405	-	650	(11,178)	128,877
17	49	8%	42,241	-	3,978	(3,538)	42,681
18	50	55%	1,103	-	800	(827)	1,076
19	51	6%	69,958	(1)	17,346	(4,718)	82,585
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 577,798	$ (1)	$ 30,340	$ (42,347)	$ 565,790
23							
24	Cross Reference					- Sect 7-TAB 7.2, Schedule 35	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	Adjustments	Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	Gas Plant in Service, Beginning	$ 1,007,359	$ 1,036,234	$ 1,023,377	$ -	$ 1,023,377	$ (12,857)	- Sect 7-TAB 7.2, Schedule 45
2	Opening Balance Adjustment	-	-	-	-	-	-	
3	Gas Plant in Service, Ending	1,023,379	1,274,815	1,263,155	-	1,263,155	(11,660)	- Sect 7-TAB 7.2, Schedule 45
4								
5	Accumulated Depreciation Beginning - Plant	$ (244,628)	$ (270,987)	$ (267,255)	$ -	$ (267,255)	$ 3,732	- Sect 7-TAB 7.2, Schedule 54
6	Opening Balance Adjustment	-	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(267,254)	(299,264)	(295,740)	-	(295,740)	3,524	- Sect 7-TAB 7.2, Schedule 54
8								
9	Negative Salvage - Beginning	$ -	$ -	$ -	$ -	$ -	$ -	
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	Negative Salvage - Ending	-	-	-	-	-	-	
12								
13	CIAC, Beginning	$ (278,712)	$ (275,728)	$ (275,876)	$ -	$ (275,876)	$ (148)	- Sect 7-TAB 7.2, Schedule 63
14	Opening Balance Adjustment	-	-	-	-	-	-	
15	CIAC, Ending	(275,876)	(276,176)	(276,364)	-	(276,364)	(188)	- Sect 7-TAB 7.2, Schedule 63
16								
17	Accumulated Amortization Beginning - CIAC	$ 50,379	$ 54,795	$ 54,800	$ -	$ 54,800	$ 5	- Sect 7-TAB 7.2, Schedule 63
18	Opening Balance Adjustment	-	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	54,799	59,218	59,227	-	59,227	9	- Sect 7-TAB 7.2, Schedule 63
20								
21	Net Plant in Service, Mid-Year	$ 534,723	$ 651,454	$ 642,662	$ -	$ 642,662	$ (8,792)	
22								
23	* Adjustment to 13-Month Average	(1,131)	56,712	24,573	-	24,573	(32,139)	
24	Work in Progress, No AFUDC	2,280	3,608	2,285	-	2,285	(1,323)	
25	Unamortized Deferred Charges	332	4,908	(2,890)	-	(2,890)	(7,798)	- Sect 7-TAB 7.2, Schedule 67
26	Cash Working Capital	1,029	134	819	(338)	481	347	- Sect 7-TAB 7.2, Schedule 72
27	Other Working Capital	10,428	12,178	9,599	-	9,599	(2,579)	- Sect 7-TAB 7.2, Schedule 72
28	Future Income Taxes Regulatory Asset	60,306	63,889	67,021	-	67,021	3,132	- Sect 7-TAB 7.2, Schedule 78
29	Future Income Taxes Regulatory Liability	(60,306)	(63,889)	(67,021)	-	(67,021)	(3,132)	- Sect 7-TAB 7.2, Schedule 78
30	**Utility Rate Base**	$ 547,661	$ 728,993	$ 677,048	$ (338)	$ 676,710	$ (52,283)	- Sect 7-TAB 7.2, Schedule 79
31								
32	* May 31, 2011 In-Service date applied to Mount Hayes LNG							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Adjustments	2012 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 1,023,377	$ 1,263,155	$ -	$ 1,263,155	$ 239,778	- Sect 7-TAB 7.2, Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	1,263,155	1,317,524	-	1,317,524	54,369	- Sect 7-TAB 7.2, Schedule 48
4							
5	Accumulated Depreciation Beginning - Plant	$ (267,255)	$ (295,740)	$ -	$ (295,740)	$ (28,485)	- Sect 7-TAB 7.2, Schedule 57
6	Opening Balance Adjustment (re Negative Salvage)	-	9,193	-	9,193	9,193	- Sect 7-TAB 7.2, Schedule 57
7	Accumulated Depreciation Ending - Plant	(295,740)	(318,482)	-	(318,482)	(22,742)	- Sect 7-TAB 7.2, Schedule 57
8							
9	Negative Salvage - Beginning	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.2, Schedule 61
10	Opening Balance Adjustment (re Negative Salvage)	-	(9,193)	-	(9,193)	(9,193)	- Sect 7-TAB 7.2, Schedule 61
11	Negative Salvage - Ending	-	(12,476)	-	(12,476)	(12,476)	- Sect 7-TAB 7.2, Schedule 61
12							
13	CIAC, Beginning	$ (275,876)	$ (276,364)	$ -	$ (276,364)	$ (488)	- Sect 7-TAB 7.2, Schedule 64
14	Opening Balance Adjustment	-	2,484	-	2,484	2,484	- Sect 7-TAB 7.2, Schedule 64
15	CIAC, Ending	(276,364)	(254,306)	-	(254,306)	22,058	- Sect 7-TAB 7.2, Schedule 64
16							
17	Accumulated Amortization Beginning - CIAC	$ 54,800	$ 59,227	$ -	$ 59,227	$ 4,427	- Sect 7-TAB 7.2, Schedule 64
18	Opening Balance Adjustment	-	(86)	-	(86)	(86)	- Sect 7-TAB 7.2, Schedule 64
19	Accumulated Amortization Ending - CIAC	59,227	63,319	-	63,319	4,092	- Sect 7-TAB 7.2, Schedule 64
20							
21	Net Plant in Service, Mid-Year	$ 642,662	$ 774,128	$ -	$ 774,128	$ 131,466	
22							
23	* Adjustment to 13-Month Average	24,573	1,210	-	1,210	(23,363)	
24	Work in Progress, No AFUDC	2,285	2,285	-	2,285	-	
25	Unamortized Deferred Charges	(2,890)	(1,096)	-	(1,096)	1,794	- Sect 7-TAB 7.2, Schedule 69
26	Cash Working Capital	481	295	-	295	(186)	- Sect 7-TAB 7.2, Schedule 73
27	Other Working Capital	9,599	11,042	-	11,042	1,443	- Sect 7-TAB 7.2, Schedule 73
28	Future Income Taxes Regulatory Asset	67,021	72,524	-	72,524	5,503	- Sect 7-TAB 7.2, Schedule 78
29	Future Income Taxes Regulatory Liability	(67,021)	(72,524)	-	(72,524)	(5,503)	- Sect 7-TAB 7.2, Schedule 78
30	**Utility Rate Base**	$ 676,710	$ 787,864	$ -	$ 787,864	$ 111,154	- Sect 7-TAB 7.2, Schedule 80
31							
32	* January 1, 2011 In-Service date for Customer Care Enhancement; October 1, 2012 In-Service date for FEVI Head Office						

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Adjustments	2013 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 1,263,155	$ 1,317,524	$ -	$ 1,317,524	$ 54,369	- Sect 7-TAB 7.2, Schedule 51
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	1,317,524	1,344,362	-	1,344,362	26,838	- Sect 7-TAB 7.2, Schedule 51
4							
5	Accumulated Depreciation Beginning - Plant	$ (295,740)	$ (318,482)	$ -	$ (318,482)	$ (22,742)	- Sect 7-TAB 7.2, Schedule 60
6	Opening Balance Adjustment	9,193	-	-	-	(9,193)	
7	Accumulated Depreciation Ending - Plant	(318,482)	(346,979)	-	(346,979)	(28,497)	- Sect 7-TAB 7.2, Schedule 60
8							
9	Negative Salvage - Beginning	$ -	$ (12,476)	$ -	$ (12,476)	$ (12,476)	- Sect 7-TAB 7.2, Schedule 62
10	Opening Balance Adjustment	(9,193)	-	-	-	9,193	
11	Negative Salvage - Ending	(12,476)	(15,874)	-	(15,874)	(3,398)	- Sect 7-TAB 7.2, Schedule 62
12							
13	CIAC, Beginning	$ (276,364)	$ (254,306)	$ -	$ (254,306)	$ 22,058	- Sect 7-TAB 7.2, Schedule 65
14	Opening Balance Adjustment	2,484	-	-	-	(2,484)	
15	CIAC, Ending	(254,306)	(250,614)	-	(250,614)	3,692	- Sect 7-TAB 7.2, Schedule 65
16							
17	Accumulated Amortization Beginning - CIAC	$ 59,227	$ 63,319	$ -	$ 63,319	$ 4,092	- Sect 7-TAB 7.2, Schedule 65
18	Opening Balance Adjustment	(86)	-	-	-	86	
19	Accumulated Amortization Ending - CIAC	63,319	67,506	-	67,506	4,187	- Sect 7-TAB 7.2, Schedule 65
20							
21	Net Plant in Service, Mid-Year	$ 774,128	$ 796,990	$ -	$ 796,990	$ 22,862	
22							
23	Adjustment to 13-Month Average	1,210	-	-	-	(1,210)	
24	Work in Progress, No AFUDC	2,285	2,285	-	2,285	-	
25	Unamortized Deferred Charges	(1,096)	3,891	-	3,891	4,987	- Sect 7-TAB 7.2, Schedule 71
26	Cash Working Capital	295	214	262	476	181	- Sect 7-TAB 7.2, Schedule 74
27	Other Working Capital	11,042	10,436	-	10,436	(606)	- Sect 7-TAB 7.2, Schedule 74
28	Future Income Taxes Regulatory Asset	72,524	76,663	-	76,663	4,139	- Sect 7-TAB 7.2, Schedule 78
29	Future Income Taxes Regulatory Liability	(72,524)	(76,663)	-	(76,663)	(4,139)	- Sect 7-TAB 7.2, Schedule 78
30	**Utility Rate Base**	$ 787,864	$ 813,816	$ 262	$ 814,078	$ 26,214	- Sect 7-TAB 7.2, Schedule 81

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2011 Projected	2012 Forecast	2013 Forecast	Reference
	(1)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4					
5	Total Regular Capital Expenditures	$ 23,464	$ 29,950	$ 29,079	
6					
7	Special Projects - CPCN's				
8	Mt. Hayes LNG Facility	31,436	-	-	
9	Victoria Regional Office	8,456	4,782	-	
10	CCE	3,170	1,581	-	
11	Total CPCN's	$ 43,062	$ 6,363	$ -	
12					
13					
14	TOTAL CAPITAL EXPENDITURES	$ 66,526	$ 36,313	$ 29,079	
15					
16					
17	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
18					
19	Regular Capital				
20	Regular Capital Expenditures	$ 23,464	$ 29,950	$ 29,079	
21	Add - Opening WIP	8,934	8,934	8,934	
22	Less - Opening WIP Adjustment	-	-	-	
23	Less - Closing WIP	(8,934)	(8,934)	(8,934)	
24	Add - AFUDC	150	139	147	- Sect 7-TAB 7.2, Schedule 45
25	Add - Overhead Capitalized	4,567	4,933	4,967	- Sect 7-TAB 7.2, Schedule 48, 51
26					
27	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 28,181	$ 35,022	$ 34,193	
28					
29	Special Projects - CPCN's				
30	CPCN Expenditures	43,062	6,363	-	
31	Add - Opening WIP	179,107	15,007	-	
32	Less - Closing WIP	(15,007)	-	-	
33	Add - AFUDC	5,801	603	-	- Sect 7-TAB 7.2, Schedule 45
34					- Sect 7-TAB 7.2, Schedule 48, 51
35	TOTAL CPCN ADDITIONS	$ 212,964	$ 21,973	$ -	
36					
37	TOTAL PLANT ADDITIONS	$ 241,145	$ 56,996	$ 34,193	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	190	-	-	-	-	-	-	190	190
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	-	-	-	-	-	-	1,219	1,219
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	-	-	-	-	-	-	6,847	6,847
11	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
12	471-00 Distribution Land Rights	1,866	-	-	-	-	-	-	1,866	1,866
13	402-01 Application Software - 12.5%	15,815	-	450	7	-	-	-	16,272	16,044
14	402-02 Application Software - 20%	2,603	-	450	11	-	-	-	3,064	2,834
15	TOTAL INTANGIBLE	28,564	-	900	18	-	-	-	29,482	29,023
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	440/441-00 Land in Fee Simple and Land Rights (Mount Hay	-	1,012	-	-	-	-	-	1,012	506
27	442-00 Structures & Improvements (Mount Hayes)	-	17,442	-	-	-	-	-	17,442	18,825
28	443-00 Gas Holders - Storage (Mount Hayes)	-	60,757	-	-	-	-	-	60,757	65,577
29	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
30	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
31	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
32	448-10 Piping (Mount Hayes)	-	11,605	-	-	-	-	-	11,605	12,525
33	448-20 Pre-treatment (Mount Hayes)	-	29,012	-	-	-	-	-	29,012	31,313
34	448-30 Liquefaction Equipment (Mount Hayes)	-	29,012	-	-	-	-	-	29,012	31,313
35	448-40 Send out Equipment (Mount Hayes)	-	23,237	-	-	-	-	-	23,237	11,619
36	448-50 Sub-station and Electric (Mount Hayes)	-	22,466	-	-	-	-	-	22,466	11,233
37	448-60 Control Room (Mount Hayes)	-	5,923	-	-	-	-	-	5,923	2,962
38	449-00 Local Storage Equipment (Mount Hayes)	-	173	-	-	-	-	-	173	187
39	TOTAL MANUFACTURED	-	200,639	-	-	-	-	-	200,639	186,060

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 2,842	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,842	$ 2,842
3	461-00 Transmission Land Rights	-	-	78	-	-	-	-	78	39
4	461-02 Land Rights - Mt. Hayes	-	801	-	-	-	-	-	801	401
5	462-00 Compressor Structures	11,705	-	-	-	-	-	-	11,705	11,705
6	463-00 Measuring Structures	7,517	-	-	-	-	-	-	7,517	7,517
7	464-00 Other Structures & Improvements	130	-	-	-	-	-	-	130	130
8	465-00 Mains	321,962	-	4,780	109	1,129	-	-	327,980	324,971
9	465-00 Mains - INSPECTION	2,758	-	550	-	130	-	-	3,438	3,098
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	-	6,015	-	-	-	-	-	6,015	6,492
12	466-00 Compressor Equipment	58,910	-	785	10	185	-	-	59,890	59,400
13	466-00 Compressor Equipment - OVERHAUL	3,882	-	1,600	-	378	-	-	5,860	4,871
14	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	5,509	-	-	-	-	-	5,509	5,946
15	467-10 Measuring & Regulating Equipment	13,995	-	100	3	24	(58)	-	14,064	14,030
16	467-20 Telemetering	41	-	-	-	-	-	-	41	41
17	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
18	468-00 Communication Structures & Equipment	3,780	-	-	-	-	-	-	3,780	3,780
19	TOTAL TRANSMISSION	469,762	12,325	7,893	122	1,846	(58)	-	491,890	487,502
20										
21	**DISTRIBUTION PLANT**									
22	470-00 Land in Fee Simple	799	-	-	-	-	-	-	799	799
23	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
24	472-00 Structures & Improvements	2,302	-	-	-	-	-	-	2,302	2,302
25	473-00 Services	173,742	-	4,977	-	1,175	(159)	-	179,735	176,739
26	474-00 House Regulators & Meter Installations	22,790	-	814	-	192	-	-	23,796	23,293
27	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
28	475-00 Mains	279,553	-	5,337	-	1,260	(69)	-	286,081	282,817
29	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
30	477-00 Measuring & Regulating Equipment	8,305	-	295	-	70	(27)	-	8,643	8,474
31	477-00 Telemetering	-	-	100	-	24	-	-	124	62
32	478-10 Meters	13,544	-	814	-	-	(312)	-	14,046	13,795
33	478-20 Instruments	-	-	-	-	-	-	-	-	-
34	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
35	TOTAL DISTRIBUTION	501,035	-	12,337	-	2,721	(567)	-	515,526	508,281
36										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1,268	-	-	-	-	-	-	1,268	1,268
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	3,959	-	-	-	-	-	-	3,959	3,959
6	- Masonry Buildings	1,005	-	167	-	-	-	-	1,172	1,089
7	- Leasehold Improvement	467	-	40	-	-	(1)	-	506	487
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	653	-	-	-	-	-	-	653	653
10	483-40 GP Furniture	328	-	101	-	-	-	-	429	379
11	483-10 GP Computer Hardware	2,010	-	600	10	-	-	-	2,620	2,315
12	483-20 GP Computer Software	261	-	-	-	-	-	-	261	261
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
15	484-00 Vehicles	5,080	-	1,207	-	-	(341)	-	5,946	5,513
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	327	-	30	-	-	(34)	-	323	325
18	485-20 Heavy Mobile Equipment	1,113	-	154	-	-	-	-	1,267	1,190
19	486-00 Small Tools & Equipment	6,757	-	35	-	-	(210)	-	6,582	6,670
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	737	-	-	-	-	(156)	-	581	659
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	24,016	-	2,334	10	-	(742)	-	25,618	24,817
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 1,023,377	$ 212,964	$ 23,464	$ 150	$ 4,567	$ (1,367)	$ -	$ 1,263,155	$ 1,235,683
33										
34	Cross Reference	- Sect 7-TAB 7.2, Schedule 39							- Sect 7-TAB 7.2, Schedule 39	
35			- Sect 7-TAB 7.2, Schedule 42							- Sect 7-TAB 7.2, Schedule 54

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	190	-	-	-	-	-	-	190	190
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	-	-	-	-	-	-	1,219	1,219
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	-	-	-	-	-	-	6,847	6,847
11	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
12	471-00 Distribution Land Rights	1,866	-	-	-	-	-	-	1,866	1,866
13	402-01 Application Software - 12.5%	16,272	5,932	600	9	-	(931)	-	21,882	25,009
14	402-02 Application Software - 20%	3,064	-	600	14	-	(96)	-	3,582	3,323
15	TOTAL INTANGIBLE	29,482	5,932	1,200	23	-	(1,027)	-	35,610	38,478
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	440/441-00 Land in Fee Simple and Land Rights (Mount Hay	1,012	-	-	-	-	-	-	1,012	1,012
27	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
28	443-00 Gas Holders - Storage (Mount Hayes)	60,757	-	750	-	-	-	-	61,507	61,132
29	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
30	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
31	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
32	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
33	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
34	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
35	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
36	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
37	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
38	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
39	TOTAL MANUFACTURED	200,639	-	750	-	-	-	-	201,389	201,014

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 2,842	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,842	$ 2,842
3	461-00 Transmission Land Rights	78	-	80	-	-	-	-	158	118
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	11,705	-	-	-	-	-	-	11,705	11,705
6	463-00 Measuring Structures	7,517	-	-	-	-	-	-	7,517	7,517
7	464-00 Other Structures & Improvements	130	-	-	-	-	-	-	130	130
8	465-00 Mains	327,980	-	3,111	71	700	-	-	331,862	329,921
9	465-00 Mains - INSPECTION	3,438	-	275	-	62	-	-	3,775	3,607
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	466-00 Compressor Equipment	59,890	-	2,457	32	553	-	-	62,932	61,411
13	466-00 Compressor Equipment - OVERHAUL	5,860	-	1,450	-	326	-	-	7,636	6,748
14	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
15	467-10 Measuring & Regulating Equipment	14,064	-	-	-	-	-	-	14,064	14,064
16	467-20 Telemetering	41	-	-	-	-	-	-	41	41
17	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
18	468-00 Communication Structures & Equipment	3,780	-	-	-	-	-	-	3,780	3,780
19	TOTAL TRANSMISSION	491,890	-	7,373	103	1,641	-	-	501,007	496,449
20										
21	**DISTRIBUTION PLANT**									
22	470-00 Land in Fee Simple	799	-	-	-	-	-	-	799	799
23	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
24	472-00 Structures & Improvements	2,302	-	-	-	-	-	-	2,302	2,302
25	473-00 Services	179,735	-	5,748	-	1,294	(161)	-	186,616	183,176
26	474-00 House Regulators & Meter Installations	23,796	-	-	-	-	-	-	23,796	23,796
27	477-00 Meters/Regulators Installations	-	-	847	-	-	-	-	847	424
28	475-00 Mains	286,081	-	8,448	-	1,902	(110)	-	296,321	291,201
29	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
30	477-00 Measuring & Regulating Equipment	8,643	-	325	-	73	(29)	-	9,012	8,828
31	477-00 Telemetering	124	-	100	-	23	-	-	247	186
32	478-10 Meters	14,046	-	847	-	-	(443)	-	14,450	14,248
33	478-20 Instruments	-	-	-	-	-	-	-	-	-
34	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
35	TOTAL DISTRIBUTION	515,526	-	16,315	-	3,292	(743)	-	534,390	524,958
36										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1,268	6,355	-	-	-	-	-	7,623	4,446
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	3,959	-	-	-	-	-	-	3,959	3,959
6	- Masonry Buildings	1,172	8,482	365	-	-	-	-	10,019	5,596
7	- Leasehold Improvement	506	361	45	-	-	(313)	-	599	914
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	653	110	6	-	-	-	-	769	711
10	483-40 GP Furniture	429	361	20	-	-	-	-	810	981
11	483-10 GP Computer Hardware	2,620	372	800	13	-	-	-	3,805	3,585
12	483-20 GP Computer Software	261	-	-	-	-	-	-	261	261
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
15	484-00 Vehicles	5,946	-	2,913	-	-	(202)	-	8,657	7,302
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	323	-	-	-	-	(11)	-	312	318
18	485-20 Heavy Mobile Equipment	1,267	-	160	-	-	-	-	1,427	1,347
19	486-00 Small Tools & Equipment	6,582	-	3	-	-	(320)	-	6,265	6,424
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	581	-	-	-	-	(10)	-	571	576
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	25,618	16,041	4,312	13	-	(856)	-	45,128	36,467
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 1,263,155	$ 21,973	$ 29,950	$ 139	$ 4,933	$ (2,626)	$ -	$ 1,317,524	$ 1,297,366
33										
34	Cross Reference	- Sect 7-TAB 7.2, Schedule 40							- Sect 7-TAB 7.2, Schedule 40	
35			- Sect 7-TAB 7.2, Schedule 42						- Sect 7-TAB 7.2, Schedule 57	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	190	-	-	-	-	-	-	190	190
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	-	-	-	-	-	-	1,219	1,219
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	-	-	-	-	-	-	6,847	6,847
11	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
12	471-00 Distribution Land Rights	1,866	-	-	-	-	-	-	1,866	1,866
13	402-01 Application Software - 12.5%	21,882	-	600	9	-	(2,743)	-	19,748	20,815
14	402-02 Application Software - 20%	3,582	-	600	14	-	(1,271)	-	2,925	3,254
15	TOTAL INTANGIBLE	35,610	-	1,200	23	-	(4,014)	-	32,819	34,215
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	440/441-00 Land in Fee Simple and Land Rights (Mount Hay	1,012	-	-	-	-	-	-	1,012	1,012
27	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
28	443-00 Gas Holders - Storage (Mount Hayes)	61,507	-	603	-	-	-	-	62,110	61,809
29	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
30	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
31	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
32	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
33	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
34	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
35	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
36	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
37	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
38	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
39	TOTAL MANUFACTURED	201,389	-	603	-	-	-	-	201,992	201,691

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 2,842	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,842	$ 2,842
3	461-00 Transmission Land Rights	158	-	82	-	-	-	-	240	199
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	11,705	-	-	-	-	-	-	11,705	11,705
6	463-00 Measuring Structures	7,517	-	-	-	-	-	-	7,517	7,517
7	464-00 Other Structures & Improvements	130	-	-	-	-	-	-	130	130
8	465-00 Mains	331,862	-	3,690	85	897	-	-	336,534	334,198
9	465-00 Mains - INSPECTION	3,775	-	-	-	-	-	-	3,775	3,775
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	466-00 Compressor Equipment	62,932	-	1,978	26	481	-	-	65,417	64,175
13	466-00 Compressor Equipment - OVERHAUL	7,636	-	-	-	-	-	-	7,636	7,636
14	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
15	467-10 Measuring & Regulating Equipment	14,064	-	-	-	-	-	-	14,064	14,064
16	467-20 Telemetering	41	-	-	-	-	-	-	41	41
17	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
18	468-00 Communication Structures & Equipment	3,780	-	-	-	-	-	-	3,780	3,780
19	TOTAL TRANSMISSION	501,007	-	5,750	111	1,378	-	-	508,246	504,627
20										
21	**DISTRIBUTION PLANT**									
22	470-00 Land in Fee Simple	799	-	-	-	-	-	-	799	799
23	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
24	472-00 Structures & Improvements	2,302	-	-	-	-	-	-	2,302	2,302
25	473-00 Services	186,616	-	6,442	-	1,567	(158)	-	194,467	190,542
26	474-00 House Regulators & Meter Installations	23,796	-	-	-	-	(444)	-	23,352	23,574
27	477-00 Meters/Regulators Installations	847	-	881	-	-	-	-	1,728	1,288
28	475-00 Mains	296,321	-	7,840	-	1,907	(102)	-	305,966	301,144
29	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
30	477-00 Measuring & Regulating Equipment	9,012	-	375	-	91	(34)	-	9,444	9,228
31	477-00 Telemetering	247	-	100	-	24	-	-	371	309
32	478-10 Meters	14,450	-	881	-	-	(443)	-	14,888	14,669
33	478-20 Instruments	-	-	-	-	-	-	-	-	-
34	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
35	TOTAL DISTRIBUTION	534,390	-	16,519	-	3,589	(1,181)	-	553,317	543,854
36										

FORTISBC ENERGY (Vancouver Island) INC. May 4, 2011 Section 7

TAB 7.2

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued) - Schedule 51

FOR THE YEAR ENDING DECEMBER 31, 2013

($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	7,623	-	-	-	-	-	-	7,623	7,623
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	3,959	-	-	-	-	-	-	3,959	3,959
6	- Masonry Buildings	10,019	-	335	-	-	-	-	10,354	10,187
7	- Leasehold Improvement	599	-	30	-	-	(58)	-	571	585
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	769	-	10	-	-	-	-	779	774
10	483-40 GP Furniture	810	-	115	-	-	-	-	925	868
11	483-10 GP Computer Hardware	3,805	-	800	13	-	(92)	-	4,526	4,166
12	483-20 GP Computer Software	261	-	-	-	-	(167)	-	94	178
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
15	484-00 Vehicles	8,657	-	3,431	-	-	(1,374)	-	10,714	9,686
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	312	-	-	-	-	-	-	312	312
18	485-20 Heavy Mobile Equipment	1,427	-	160	-	-	-	-	1,587	1,507
19	486-00 Small Tools & Equipment	6,265	-	126	-	-	(370)	-	6,021	6,143
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	571	-	-	-	-	(99)	-	472	522
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	45,128	-	5,007	13	-	(2,160)	-	47,988	46,558
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 1,317,524	$ -	$ 29,079	$ 147	$ 4,967	$ (7,355)	$ -	$ 1,344,362	$ 1,330,943
33										
34	Cross Reference	- Sect 7-TAB 7.2, Schedule 41							- Sect 7-TAB 7.2, Schedule 41	
35			- Sect 7-TAB 7.2, Schedule 42						- Sect 7-TAB 7.2, Schedule 60	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	190	3.13%	6	-	-	68	74
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	2.30%	28	-	-	592	620
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	0.00%	-	-	-	1,100	1,100
11	461-13 IP Land Rights Whistler	24	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	1,866	0.00%	-	-	-	235	235
13	402-01 Application Software - 12.5%	16,044	12.50%	2,005	-	-	7,475	9,480
14	402-02 Application Software - 20%	2,834	20.00%	567	-	-	791	1,358
15	TOTAL INTANGIBLE	29,023		2,606	-	-	10,261	12,867
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	0.00%	-	-	-	-	-
25	440/441-00 Land in Fee Simple and Land Rights (Mou	506	0.00%	-	-	-	-	-
26	442-00 Structures & Improvements (Mount Hayes)	18,825	4.00%	407	-	-	-	407
27	443-00 Gas Holders - Storage (Mount Hayes)	65,577	1.67%	592	-	-	-	592
28	446-00 Compressor Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
29	447-00 Measuring & Regulating Equipment (Mount Ha	-	0.00%	-	-	-	-	-
30	448-00 Purification Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
31	448-10 Piping (Mount Hayes)	12,525	2.50%	169	-	-	-	169
32	448-20 Pre-treatment (Mount Hayes)	31,313	4.00%	677	-	-	-	677
33	448-30 Liquefaction Equipment (Mount Hayes)	31,313	2.50%	423	-	-	-	423
34	448-40 Send out Equipment (Mount Hayes)	11,619	2.50%	290	-	-	-	290
35	448-50 Sub-station and Electric (Mount Hayes)	11,233	2.50%	281	-	-	-	281
36	448-60 Control Room (Mount Hayes)	2,962	6.67%	198	-	-	-	198
37	449-00 Local Storage Equipment (Mount Hayes)	187	2.86%	3	-	-	-	3
38	TOTAL MANUFACTURED	186,060		3,040	-	-	-	3,040

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 2,842	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	39	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	401	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	11,705	3.72%	435	-	-	3,867	4,302
6	463-00 Measuring Structures	7,517	2.87%	216	-	-	2,665	2,881
7	464-00 Other Structures & Improvements	130	2.87%	4	-	-	20	24
8	465-00 Mains	324,971	1.73%	5,622	-	-	92,731	98,353
9	465-00 Mains - INSPECTION	3,098	14.29%	443	-	-	324	767
10	465-11 IP Transmission Pipeline - Whistler	41,927	1.73%	725	-	-	786	1,511
11	465-30 Mt Hayes - Mains	6,492	1.54%	54	-	-	-	54
12	465-10 Mains - Byron Creek	-	0.00%	-	-	-	-	-
13	466-00 Compressor Equipment	59,400	3.19%	1,895	-	-	17,034	18,929
14	466-00 Compressor Equipment - OVERHAUL	4,871	26.76%	1,303	-	-	1,654	2,957
15	467-00 Mt. Hayes - Measuring and Regulating Equipm	5,946	3.70%	119	-	-	-	119
16	467-10 Measuring & Regulating Equipment	14,030	5.59%	784	-	(58)	3,891	4,617
17	467-20 Telemetering	41	5.59%	2	-	-	-	2
18	467-31 IP Intermediate Pressure Whistler	313	5.59%	18	-	-	14	32
19	467-20 Measuring & Regulating Equipment - Byron Cre	-	0.00%	-	-	-	-	-
20	468-00 Communication Structures & Equipment	3,780	10.07%	381	-	-	2,093	2,474
21	TOTAL TRANSMISSION	487,502		12,001	-	(58)	125,079	137,022
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	799	0.00%	-	-	-	-	-
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	2,302	3.21%	74	-	-	942	1,016
27	473-00 Services	176,739	1.91%	3,376	-	(159)	37,262	40,479
28	474-00 House Regulators & Meter Installations	23,293	3.45%	804	-	-	6,074	6,878
29	477-00 Meters/Regulators Installations	-	4.55%	-	-	-	-	-
30	475-00 Mains	282,817	1.62%	4,582	-	(69)	71,838	76,351
31	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
32	477-00 Measuring & Regulating Equipment	8,474	4.60%	390	-	(27)	3,197	3,560
33	477-00 Telemetering	62	0.00%	-	-	-	-	-
34	478-10 Meters	13,795	4.37%	603	-	(312)	4,110	4,401
35	478-20 Instruments	-	0.00%	-	-	-	-	-
36	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
37	TOTAL DISTRIBUTION	508,281		9,829	-	(567)	123,423	132,685
38								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	1,268	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	3,959	4.36%	173	-	-	835	1,008
6	- Masonry Buildings	1,089	4.36%	47	-	-	63	110
7	- Leasehold Improvement	487	20.00%	97	-	(1)	238	334
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	653	6.67%	44	-	-	495	539
10	483-40 GP Furniture	379	5.00%	19	-	-	30	49
11	483-10 GP Computer Hardware	2,315	20.00%	463	-	-	707	1,170
12	483-20 GP Computer Software	261	20.00%	52	-	-	99	151
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	51	20.00%	10	-	-	29	39
15	484-00 Vehicles	5,513	17.88%	986	-	(341)	1,897	2,542
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	325	6.34%	21	-	(34)	167	154
18	485-20 Heavy Mobile Equipment	1,190	7.35%	87	-	-	143	230
19	486-00 Small Tools & Equipment	6,670	5.00%	333	-	(210)	3,328	3,451
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	659	6.67%	44	-	(156)	461	349
24	- Radio	-	0.00%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	24,817		2,376	-	(742)	8,492	10,126
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 1,235,683		$ 29,852	$ -	$ (1,367)	$ 267,255	$ 295,740
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			(394)				
35	**Net Depreciation Expense**			$ 29,458				
36								
37	Cross Reference	- Sect 7-TAB 7.2, Schedule 45		- Sect 7-TAB 7.2, Schedule 27			- Sect 7-TAB 7.2, Schedule 39	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	190	3.07%	6	-	-	74	80
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	1.88%	23	-	-	620	643
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	0.00%	-	-	-	1,100	1,100
11	461-13 IP Land Rights Whistler	24	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	1,866	0.00%	-	-	-	235	235
13	402-01 Application Software - 12.5%	25,009	12.50%	2,755	-	(931)	9,480	11,304
14	402-02 Application Software - 20%	3,323	20.00%	664	-	(96)	1,358	1,926
15	TOTAL INTANGIBLE	38,478		3,448	-	(1,027)	12,867	15,288
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	0.00%	-	-	-	-	-
25	440/441-00 Land in Fee Simple and Land Rights (Mou	1,012	0.00%	-	-	-	-	-
26	442-00 Structures & Improvements (Mount Hayes)	17,442	4.00%	698	-	-	407	1,105
27	443-00 Gas Holders - Storage (Mount Hayes)	61,132	1.67%	1,021	-	-	592	1,613
28	446-00 Compressor Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
29	447-00 Measuring & Regulating Equipment (Mount Ha	-	0.00%	-	-	-	-	-
30	448-00 Purification Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
31	448-10 Piping (Mount Hayes)	11,605	2.50%	290	-	-	169	459
32	448-20 Pre-treatment (Mount Hayes)	29,012	4.00%	1,160	-	-	677	1,837
33	448-30 Liquefaction Equipment (Mount Hayes)	29,012	2.50%	725	-	-	423	1,148
34	448-40 Send out Equipment (Mount Hayes)	23,237	2.50%	581	-	-	290	871
35	448-50 Sub-station and Electric (Mount Hayes)	22,466	2.50%	562	-	-	281	843
36	448-60 Control Room (Mount Hayes)	5,923	6.67%	395	-	-	198	593
37	449-00 Local Storage Equipment (Mount Hayes)	173	2.86%	5	-	-	3	8
38	TOTAL MANUFACTURED	201,014		5,437	-	-	3,040	8,477

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 2,842	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	118	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	801	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	11,705	3.56%	417	(219)	-	4,302	4,500
6	463-00 Measuring Structures	7,517	3.02%	227	(95)	-	2,881	3,013
7	464-00 Other Structures & Improvements	130	2.85%	4	-	-	24	28
8	465-00 Mains	329,921	1.55%	5,114	(2,672)	-	98,353	100,795
9	465-00 Mains - INSPECTION	3,607	14.29%	515	-	-	767	1,282
10	465-11 IP Transmission Pipeline - Whistler	41,927	1.43%	600	-	-	1,511	2,111
11	465-30 Mt Hayes - Mains	6,015	1.54%	93	-	-	54	147
12	465-10 Mains - Byron Creek	-	0.00%	-	-	-	-	-
13	466-00 Compressor Equipment	61,411	2.90%	1,781	(404)	-	18,929	20,306
14	466-00 Compressor Equipment - OVERHAUL	6,748	26.76%	1,806	-	-	2,957	4,763
15	467-00 Mt. Hayes - Measuring and Regulating Equipm	5,509	3.70%	204	-	-	119	323
16	467-10 Measuring & Regulating Equipment	14,064	4.30%	605	(72)	-	4,617	5,150
17	467-20 Telemetering	41	4.30%	2	-	-	2	4
18	467-31 IP Intermediate Pressure Whistler	313	4.00%	13	-	-	32	45
19	467-20 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-
20	468-00 Communication Structures & Equipment	3,780	11.97%	452	-	-	2,474	2,926
21	TOTAL TRANSMISSION	496,449		11,833	(3,462)	-	137,022	145,393
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	799	0.00%	-	-	-	-	-
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	2,302	3.07%	71	(22)	-	1,016	1,065
27	473-00 Services	183,176	2.00%	3,664	(3,009)	(161)	40,479	40,973
28	474-00 House Regulators & Meter Installations	23,796	5.76%	1,371	97	-	6,878	8,346
29	477-00 Meters/Regulators Installations	424	4.55%	19	-	-	-	19
30	475-00 Mains	291,201	1.49%	4,339	(2,845)	(110)	76,351	77,735
31	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
32	477-00 Measuring & Regulating Equipment	8,828	4.35%	384	(75)	(29)	3,560	3,840
33	477-00 Telemetering	186	0.00%	-	-	-	-	-
34	478-10 Meters	14,248	6.35%	905	123	(443)	4,401	4,986
35	478-20 Instruments	-	0.00%	-	-	-	-	-
36	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
37	TOTAL DISTRIBUTION	524,958		10,753	(5,731)	(743)	132,685	136,964
38								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	4,446	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	3,959	6.44%	255	-	-	1,008	1,263
6	- Masonry Buildings	5,596	2.21%	124	-	-	110	234
7	- Leasehold Improvement	914	4.16%	30	-	(313)	334	51
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	711	6.67%	47	-	-	539	586
10	483-40 GP Furniture	981	5.00%	40	-	-	49	89
11	483-10 GP Computer Hardware	3,585	20.00%	680	-	-	1,170	1,850
12	483-20 GP Computer Software	261	12.50%	33	-	-	151	184
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	51	20.00%	10	-	-	39	49
15	484-00 Vehicles	7,302	17.72%	1,294	-	(202)	2,542	3,634
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	318	5.91%	19	-	(11)	154	162
18	485-20 Heavy Mobile Equipment	1,347	14.75%	199	-	-	230	429
19	486-00 Small Tools & Equipment	6,424	5.00%	321	-	(320)	3,451	3,452
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	576	6.67%	38	-	(10)	349	377
24	- Radio	-	0.00%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	36,467		3,090	-	(856)	10,126	12,360
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 1,297,366		$ 34,561	$ (9,193)	$ (2,626)	$ 295,740	$ 318,482
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			(518)				
35	**Net Depreciation Expense**			$ 34,043				
36								
37	Cross Reference	- Sect 7-TAB 7.2, Schedule 48		- Sect 7-TAB 7.2, Schedule 28			- Sect 7-TAB 7.2, Schedule 40	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	190	3.07%	6	-	-	80	86
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	1,219	1.88%	23	-	-	643	666
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	6,847	0.00%	-	-	-	1,100	1,100
11	461-13 IP Land Rights Whistler	24	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	1,866	0.00%	-	-	-	235	235
13	402-01 Application Software - 12.5%	20,815	12.50%	2,602	-	(2,743)	11,304	11,163
14	402-02 Application Software - 20%	3,254	20.00%	651	-	(1,271)	1,926	1,306
15	TOTAL INTANGIBLE	34,215		3,282	-	(4,014)	15,288	14,556
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	0.00%	-	-	-	-	-
25	440/441-00 Land in Fee Simple and Land Rights (Mou	1,012	0.00%	-	-	-	-	-
26	442-00 Structures & Improvements (Mount Hayes)	17,442	4.00%	698	-	-	1,105	1,803
27	443-00 Gas Holders - Storage (Mount Hayes)	61,809	1.67%	1,032	-	-	1,613	2,645
28	446-00 Compressor Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
29	447-00 Measuring & Regulating Equipment (Mount Ha	-	0.00%	-	-	-	-	-
30	448-00 Purification Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-
31	448-10 Piping (Mount Hayes)	11,605	2.50%	290	-	-	459	749
32	448-20 Pre-treatment (Mount Hayes)	29,012	4.00%	1,160	-	-	1,837	2,997
33	448-30 Liquefaction Equipment (Mount Hayes)	29,012	2.50%	725	-	-	1,148	1,873
34	448-40 Send out Equipment (Mount Hayes)	23,237	2.50%	581	-	-	871	1,452
35	448-50 Sub-station and Electric (Mount Hayes)	22,466	2.50%	562	-	-	843	1,405
36	448-60 Control Room (Mount Hayes)	5,923	6.67%	395	-	-	593	988
37	449-00 Local Storage Equipment (Mount Hayes)	173	2.86%	5	-	-	8	13
38	TOTAL MANUFACTURED	201,691		5,448	-	-	8,477	13,925

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 2,842	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	199	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	801	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	11,705	3.56%	417	-	-	4,500	4,917
6	463-00 Measuring Structures	7,517	3.02%	227	-	-	3,013	3,240
7	464-00 Other Structures & Improvements	130	2.85%	4	-	-	28	32
8	465-00 Mains	334,198	1.55%	5,180	-	-	100,795	105,975
9	465-00 Mains - INSPECTION	3,775	14.29%	539	-	-	1,282	1,821
10	465-11 IP Transmission Pipeline - Whistler	41,927	1.43%	600	-	-	2,111	2,711
11	465-30 Mt Hayes - Mains	6,015	1.54%	93	-	-	147	240
12	465-10 Mains - Byron Creek	-	0.00%	-	-	-	-	-
13	466-00 Compressor Equipment	64,175	2.90%	1,861	-	-	20,306	22,167
14	466-00 Compressor Equipment - OVERHAUL	7,636	26.76%	2,044	-	-	4,763	6,807
15	467-00 Mt. Hayes - Measuring and Regulating Equipm	5,509	3.70%	204	-	-	323	527
16	467-10 Measuring & Regulating Equipment	14,064	4.30%	605	-	-	5,150	5,755
17	467-20 Telemetering	41	4.30%	2	-	-	4	6
18	467-31 IP Intermediate Pressure Whistler	313	4.00%	13	-	-	45	58
19	467-20 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-
20	468-00 Communication Structures & Equipment	3,780	11.97%	452	-	-	2,926	3,378
21	TOTAL TRANSMISSION	504,627		12,241	-	-	145,393	157,634
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	799	0.00%	-	-	-	-	-
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	2,302	3.07%	71	-	-	1,065	1,136
27	473-00 Services	190,542	2.00%	3,811	-	(158)	40,973	44,626
28	474-00 House Regulators & Meter Installations	23,574	5.76%	1,358	-	(444)	8,346	9,260
29	477-00 Meters/Regulators Installations	1,288	4.55%	59	-	-	19	78
30	475-00 Mains	301,144	1.49%	4,487	-	(102)	77,735	82,120
31	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
32	477-00 Measuring & Regulating Equipment	9,228	4.35%	401	-	(34)	3,840	4,207
33	477-00 Telemetering	309	0.00%	-	-	-	-	-
34	478-10 Meters	14,669	6.35%	932	-	(443)	4,986	5,475
35	478-20 Instruments	-	0.00%	-	-	-	-	-
36	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
37	TOTAL DISTRIBUTION	543,854		11,119	-	(1,181)	136,964	146,902
38								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account (1)	Mid-year GPIS for Depreciation (2)	Annual Depreciation Rate % (3)	Provision 2013 (Cr.) (4)	Provision Adjust-ments (5)	Retirements (6)	Accumulated 12/31/2012 (7)	Accumulated 12/31/2013 (8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	7,623	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	3,959	6.44%	255	-	-	1,263	1,518
6	- Masonry Buildings	10,187	2.21%	225	-	-	234	459
7	- Leasehold Improvement	585	4.16%	24	-	(58)	51	17
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	774	6.67%	52	-	-	586	638
10	483-40 GP Furniture	868	5.00%	43	-	-	89	132
11	483-10 GP Computer Hardware	4,166	20.00%	833	-	(92)	1,850	2,591
12	483-20 GP Computer Software	178	12.50%	22	-	(167)	184	39
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	51	20.00%	10	-	-	49	59
15	484-00 Vehicles	9,686	17.72%	1,716	-	(1,374)	3,634	3,976
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	312	5.91%	18	-	-	162	180
18	485-20 Heavy Mobile Equipment	1,507	14.75%	222	-	-	429	651
19	486-00 Small Tools & Equipment	6,143	5.00%	307	-	(370)	3,452	3,389
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	522	6.67%	35	-	(99)	377	313
24	- Radio	-	0.00%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	46,558		3,762	-	(2,160)	12,360	13,962
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 1,330,943		$ 35,852	$ -	$ (7,355)	$ 318,482	$ 346,979
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			(687)				
35	**Net Depreciation Expense**			$ 35,165				
36								
37	Cross Reference	- Sect 7-TAB 7.2, Schedule 51		- Sect 7-TAB 7.2, Schedule 29			- Sect 7-TAB 7.2, Schedule 41	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	11,705	0.18%	21	219	-	-	-	240
3	463-00 Measuring Structures	7,517	0.00%	-	95	-	-	-	95
4	464-00 Other Structures & Improvements	130	0.14%	-	-	-	-	-	-
5	465-00 Mains	329,921	0.17%	571	2,672	-	-	-	3,243
6	466-00 Compressor Equipment	61,411	0.30%	184	404	-	-	-	588
7	467-10 Measuring & Regulating Equipment	14,064	0.21%	30	72	-	-	-	102
8	468-00 Communication Structures & Equipment	3,780	2.21%	84	-	-	-	-	84
9	TOTAL TRANSMISSION	496,449		890	3,462	-	-	-	4,352
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	2,302	0.17%	4	22	-	-	-	26
13	473-00 Services	183,176	1.02%	1,868	3,009	(250)	-	-	4,627
14	474-00 House Regulators & Meter Installations	23,796	0.77%	183	(97)	-	-	-	86
15	475-00 Mains	291,201	0.31%	903	2,845	(207)	-	-	3,541
16	477-00 Measuring & Regulating Equipment	8,828	0.00%	-	75	(175)	-	-	(100)
17	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
18	478-10 Meters	14,248	0.45%	64	(123)	-	-	-	(59)
19	TOTAL DISTRIBUTION	524,958		3,025	5,731	(632)	-	-	8,124
20									
21	TOTALS	$ 1,297,366		$ 3,915	$ 9,193	$ (632)	$ -	$ -	$ 12,476
22									
23	Cross Reference	- Sect 7-TAB 7.2, Schedule 48		- Sect 7-TAB 7.2, Schedule 28				- Sect 7-TAB 7.2, Schedule 40	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	11,705	0.18%	21	-	-	-	240	261
3	463-00 Measuring Structures	7,517	0.00%	-	-	-	-	95	95
4	464-00 Other Structures & Improvements	130	0.14%	-	-	-	-	-	-
5	465-00 Mains	334,198	0.17%	578	-	-	-	3,243	3,821
6	466-00 Compressor Equipment	64,175	0.30%	193	-	-	-	588	781
7	467-10 Measuring & Regulating Equipment	14,064	0.21%	30	-	-	-	102	132
8	468-00 Communication Structures & Equipment	3,780	2.21%	84	-	-	-	84	168
9	TOTAL TRANSMISSION	504,627		906	-	-	-	4,352	5,258
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	2,302	0.17%	4	-	-	-	26	30
13	473-00 Services	190,542	1.02%	1,944	-	(250)	-	4,627	6,321
14	474-00 House Regulators & Meter Installations	23,574	0.77%	182	-	-	-	86	268
15	475-00 Mains	301,144	0.31%	934	-	(223)	-	3,541	4,252
16	477-00 Measuring & Regulating Equipment	9,228	0.00%	-	-	(175)	-	(100)	(275)
17	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
18	478-10 Meters	14,669	0.45%	66	-	-	-	(59)	7
19	TOTAL DISTRIBUTION	543,854		3,140	-	(648)	-	8,124	10,616
20									
21	TOTALS	$ 1,330,943		$ 4,046	$ -	$ (648)	$ -	$ 12,476	$ 15,874
22									
23	Cross Reference	- Sect 7-TAB 7.2, Schedule 51		- Sect 7-TAB 7.2, Schedule 29				- Sect 7-TAB 7.2, Schedule 41	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 96,770	$ -	$ 488	$ -	$ 97,258	
4							
5	Transmission Contributions	112,949	-	-	-	112,949	
6							
7	FEW Contribution for Whistler Pipeline	17,034	-	-	-	17,034	
8	Government Loans Contribution	49,123	-	-	-	49,123	
9							
10	TOTAL Contributions	275,876	-	488	-	276,364	- Sect 7-TAB 7.2, Schedule 39
11							
12							
13							
14	**Amortization**						
15							
16	Distribution Contributions	(23,432)	-	(1,829)	-	(25,261)	
17							
18	Transmission Contributions	(31,073)	-	(2,303)	-	(33,376)	
19							
20	FEW Contribution for Whistler Pipeline	(295)	-	(295)	-	(590)	
21	Government Loans Contribution	-	-	-	-	-	
22							
23	TOTAL CIAC Amortization	(54,800)	-	(4,427)	-	(59,227)	- Sect 7-TAB 7.2, Schedule 39
24							
25	**NET CONTRIBUTIONS**	$ 221,076	$ -	$ (3,939)	$ -	$ 217,137	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 Additions	2012 Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 97,258	$ -	$ 426	$ -	$ 97,684	
4							
5	Transmission Contributions	112,949	-	-	-	112,949	
6							
7	FEW Contribution for Whistler Pipeline	17,034	(2,484)	-	-	14,550	
8	Government Loans Contribution	49,123	-	-	(20,000)	29,123	
9							
10	TOTAL Contributions	276,364	(2,484)	426	(20,000)	254,306	- Sect 7-TAB 7.2, Schedule 40
11							
12							
13							
14	**Amortization**						
15							
16	Distribution Contributions	(25,261)	-	(1,878)	-	(27,139)	
17							
18	Transmission Contributions	(33,376)	-	(2,048)	-	(35,424)	
19							
20	FEW Contribution for Whistler Pipeline	(590)	86	(252)	-	(756)	
21	Government Loans Contribution	-	-	-	-	-	
22							
23	TOTAL CIAC Amortization	(59,227)	86	(4,178)	-	(63,319)	- Sect 7-TAB 7.2, Schedule 40
24							
25	**NET CONTRIBUTIONS**	$ 217,137	$ (2,398)	$ (3,752)	$ (20,000)	$ 190,987	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 Additions	2013 Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 97,684	$ -	$ 431	$ -	$ 98,115	
4							
5	Transmission Contributions	112,949	-	-	-	112,949	
6							
7	FEW Contribution for Whistler Pipeline	14,550	-	-	-	14,550	
8	Government Loans Contribution	29,123	-	-	(4,123)	25,000	
9							
10	TOTAL Contributions	254,306	-	431	(4,123)	250,614	- Sect 7-TAB 7.2, Schedule 41
11							
12							
13							
14	**Amortization**						
15							
16	Distribution Contributions	(27,139)	-	(1,887)	-	(29,026)	
17							
18	Transmission Contributions	(35,424)	-	(2,048)	-	(37,472)	
19							
20	FEW Contribution for Whistler Pipeline	(756)	-	(252)	-	(1,008)	
21	Government Loans Contribution	-	-	-	-	-	
22							
23	TOTAL CIAC Amortization	(63,319)	-	(4,187)	-	(67,506)	- Sect 7-TAB 7.2, Schedule 41
24							
25	**NET CONTRIBUTIONS**	$ 190,987	$ -	$ (3,756)	$ (4,123)	$ 183,108	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Gas Cost Variance Account (GCVA)	3,282	-	(11,053)	2,929	(8,124)	(3,282)	-	-	(8,124)	(2,421)
3											
4	Energy Policy Related										
5	Energy Efficiency & Conservation (EEC)	1,187	-	2,000	(530)	1,470	(120)	-	-	2,537	1,862
6	NGV Conversion Grants	-	-	16	(4)	12	-	-	-	12	6
7											
8	Non-Controllable Items										
9	Insurance Variance	-	-	2	(1)	1	(1)	-	-	-	-
10	Pension & OPEB Variance	-	-	685	-	685	(685)	-	-	-	-
11	BCUC Levies Variance	-	-	-	-	-	-	-	-	-	-
12	Olympics Security Costs Deferral	133	-	-	-	-	(44)	-	-	89	111
13	IFRS Conversion Costs	79	-	-	-	-	(26)	-	-	53	66
14	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
15	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
16	Vancouver Island HST Implementation	(49)	-	(84)	-	(84)	-	-	-	(133)	(91)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries: Rider	Recoveries: Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 55	$ -	$ -	$ -	$ -	$ (14)	$ -	$ -	$ 41	$ 48
3	2010-2011 Revenue Requirement Application	126	-	-	-	-	(126)	-	-	-	63
4	2012-2013 Revenue Requirement Application	-	-	127	(34)	93	-	-	-	93	46
5	CCE CPCN Application	26	-	-	-	-	(7)	-	-	20	23
6	Long Term Resource Plan Application	-	-	19	(5)	14	-	-	-	14	7
7	Victoria Regional Centre CPCN Application	12	-	78	(21)	57	-	-	-	69	41
8											
9	Other										
10	Pension & OPEB Funding	(4,514)	-	(1,279)	-	(1,279)	-	-	-	(5,793)	(5,154)
11	Deferred Removal Costs	325	-	167	(44)	123	-	-	-	447	386
12	Gains and Losses on Asset Disposition	660	-	-	-	-	-	-	-	660	660
13	PCEC Start Up Costs	1,096	-	-	-	-	(44)	-	-	1,052	1,074
14	2010-2011 Customer Service O&M and COS	-	-	-	-	-	-	-	-	-	-
15	Gas Asset Records Project	-	-	-	-	-	-	-	-	-	-
16	BC OneCall Project	-	-	-	-	-	-	-	-	-	-
17	IFRS Transitional Costs	382	-	-	-	-	-	-	-	382	382
18											
19	Total Deferred Charges for Rate Base	$ 2,801	$ -	$ (9,322)	$ 2,291	$ (7,031)	$ (4,350)	$ -	$ -	$ (8,580)	$ (2,890)
20											
21	Cross Reference						- Sect 7-TAB 7.2, Schedule 27			- Sect 7-TAB 7.2, Schedule 39	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Gas Cost Variance Account (GCVA)	(8,124)	-	-	-	-	8,124	-	-	(0)	(4,062)
3											
4	Energy Policy Related										
5	Energy Efficiency & Conservation (EEC)	2,537	-	2,000	(500)	1,500	(281)	-	-	3,756	3,147
6	NGV Conversion Grants	12	-	16	(4)	12	(2)	-	-	22	17
7											
8	Non-Controllable Items										
9	Insurance Variance	-	-	-	-	-	-	-	-	-	-
10	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-	-
11	BCUC Levies Variance	-	-	-	-	-	-	-	-	-	-
12	Olympics Security Costs Deferral	89	-	-	-	-	(45)	-	-	44	67
13	IFRS Conversion Costs	53	-	-	-	-	(26)	-	-	26	39
14	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
15	Vancouver Island Joint Venture Litigation Costs	-	137	-	-	-	(137)	-	-	-	68
16	Vancouver Island HST Implementation	(133)	-	-	-	-	133	-	-	-	(66)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 41	$ -	$ -	$ -	$ -	$ (14)	$ -	$ -	$ 27	$ 34
3	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
4	2012-2013 Revenue Requirement Application	93	-	-	-	-	(46)	-	-	46	70
5	CCE CPCN Application	20	-	-	-	-	(6)	-	-	14	17
6	Long Term Resource Plan Application	14	-	7	(2)	5	-	-	-	19	16
7	Victoria Regional Centre CPCN Application	69	-	-	-	-	(69)	-	-	-	35
8											
9	Other										
10	Pension & OPEB Funding	(5,793)	-	(10,980)	-	(10,980)	-	-	-	(16,773)	(11,283)
11	Deferred Removal Costs	447	-	-	-	-	(224)	-	-	224	336
12	Gains and Losses on Asset Disposition	660	382	-	-	-	(52)	-	-	990	1,016
13	PCEC Start Up Costs	1,052	-	-	-	-	(44)	-	-	1,008	1,030
14	2010-2011 Customer Service O&M and COS	-	2,604	497	(124)	373	(325)	-	-	2,651	2,627
15	Gas Asset Records Project	-	-	200	(50)	150	(30)	-	-	120	60
16	BC OneCall Project	-	-	125	(31)	94	(19)	-	-	75	38
17	IFRS Transitional Costs	382	(382)	12,325	-	12,325	(927)	-	-	11,398	5,699
18											
19	Total Deferred Charges for Rate Base	$ (8,580)	$ 2,741	$ 4,191	$ (711)	$ 3,479	$ 6,008	$ -	$ -	$ 3,648	$ (1,096)
20											
21	Cross Reference						- Sect 7-TAB 7.2, Schedule 28			- Sect 7-TAB 7.2, Schedule 40	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Gas Cost Variance Account (GCVA)	(0)	-	-	-	-	-	-	-	(0)	-
3											
4	Energy Policy Related										
5	Energy Efficiency & Conservation (EEC)	3,756	-	2,000	(500)	1,500	(431)	-	-	4,825	4,290
6	NGV Conversion Grants	22	-	16	(4)	12	(5)	-	-	29	26
7											
8	Non-Controllable Items										
9	Insurance Variance	-	-	-	-	-	-	-	-	-	-
10	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-	-
11	BCUC Levies Variance	-	-	-	-	-	-	-	-	-	-
12	Olympics Security Costs Deferral	44	-	-	-	-	(44)	-	-	0	22
13	IFRS Conversion Costs	26	-	-	-	-	(26)	-	-	0	13
14	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
15	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
16	Vancouver Island HST Implementation	-	-	-	-	-	-	-	-	-	-

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 27	$ -	$ -	$ -	$ -	$ (14)	$ -	$ -	$ 13	$ 20
3	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
4	2012-2013 Revenue Requirement Application	46	-	-	-	-	(46)	-	-	(0)	23
5	CCE CPCN Application	14	-	-	-	-	(6)	-	-	8	11
6	Long Term Resource Plan Application	19	-	20	(5)	15	(17)	-	-	17	18
7	Victoria Regional Centre CPCN Application	-	-	-	-	-	-	-	-	-	-
8											
9	Other										
10	Pension & OPEB Funding	(16,773)	-	1,008	-	1,008	-	-	-	(15,765)	(16,269)
11	Deferred Removal Costs	224	-	-	-	-	(224)	-	-	0	112
12	Gains and Losses on Asset Disposition	990	-	-	-	-	(52)	-	-	938	964
13	PCEC Start Up Costs	1,008	-	-	-	-	(44)	-	-	964	986
14	2010-2011 Customer Service O&M and COS	2,651	-	-	-	-	(372)	-	-	2,279	2,465
15	Gas Asset Records Project	120	-	225	(56)	169	(64)	-	-	225	173
16	BC OneCall Project	75	-	125	(31)	94	(38)	-	-	131	103
17	IFRS Transitional Costs	11,398	-	-	-	-	(927)	-	-	10,471	10,935
18											
19	Total Deferred Charges for Rate Base	$ 3,648	$ -	$ 3,394	$ (597)	$ 2,798	$ (2,310)	$ -	$ -	$ 4,135	$ 3,891
20											
21	Cross Reference						- Sect 7-TAB 7.2, Schedule 29			- Sect 7-TAB 7.2, Schedule 41	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 2,163	$ 1,909	$ 2,038	$ 1,700	$ (209)	- Sect 7-TAB 7.2, Schedule 75
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(890)	(1,045)	(968)	(968)	77	
9							
10	Withholdings From Employees	(243)	(730)	(251)	(251)	479	
11							
12	Subtotal	1,029	134	819	481	347	- Sect 7-TAB 7.2, Schedule 39
13							
14	**Other Working Capital Items**						
15	Transmission Line Pack Gas	822	1,321	610	610	(711)	
16	Gas in Storage	9,895	11,146	9,280	9,280	(1,866)	
17							
18	Subtotal	10,428	12,178	9,599	9,599	(2,579)	- Sect 7-TAB 7.2, Schedule 39
19							
20	Total	$ 11,458	$ 12,312	$ 10,418	$ 10,080	$ (2,232)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 1,700	$ 1,688	$ 1,688	$ (12)	- Sect 7-TAB 7.2, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(968)	(1,132)	(1,132)	(164)	
9						
10	Withholdings From Employees	(251)	(261)	(261)	(10)	
11						
12	Subtotal	481	295	295	(186)	- Sect 7-TAB 7.2, Schedule 40
13						
14	**Other Working Capital Items**					
15	Transmission Line Pack Gas	610	728	728	118	
16	Gas in Storage	9,280	10,605	10,605	1,325	
17						
18	Subtotal	9,599	11,042	11,042	1,443	- Sect 7-TAB 7.2, Schedule 40
19						
20	Total	$ 10,080	$ 11,337	$ 11,337	$ 1,257	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Cost of Service Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 1,688	$ 1,689	$ 1,951	$ 263	- Sect 7-TAB 7.2, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(1,132)	(1,206)	(1,206)	(74)	
9						
10	Withholdings From Employees	(261)	(269)	(269)	(8)	
11						
12	Subtotal	295	214	476	181	- Sect 7-TAB 7.2, Schedule 41
13						
14	**Other Working Capital Items**					
15	Transmission Line Pack Gas	728	792	792	64	
16	Gas in Storage	10,605	9,935	9,935	(670)	
17						
18	Subtotal	11,042	10,436	10,436	(606)	- Sect 7-TAB 7.2, Schedule 41
19						
20	Total	$ 11,337	$ 10,650	$ 10,912	$ (425)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Days	2011 Expenses	2011 Cash Working Capital	2012 Days	2012 Expenses	2012 Cash Working Capital	2013 Days	2013 Expenses	2013 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	39.4			39.1			39.1			- Sect 7-TAB 7.2, Schedule 76
4	Expense Lead Days	33.9			34.8			34.9			- Sect 7-TAB 7.2, Schedule 77
5											- Sect 7-TAB 7.2, Schedule 72
6	Net Lead/(Lag) Days	5.5	$ 135,223	$ 2,038	4.3	$ 143,273	$ 1,688	4.2	$ 146,772	$ 1,689	- Sect 7-TAB 7.2, Schedule 73
7											- Sect 7-TAB 7.2, Schedule 74
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	39.5			39.1			39.0			- Sect 7-TAB 7.2, Schedule 76
13	Expense Lead Days	34.7			34.8			34.3			- Sect 7-TAB 7.2, Schedule 77
14											- Sect 7-TAB 7.2, Schedule 72
15	Net Lead/(Lag) Days	4.8	$ 129,235	$ 1,700	4.3	$ 143,274	$ 1,688	4.7	$ 151,491	$ 1,951	- Sect 7-TAB 7.2, Schedule 73
16											- Sect 7-TAB 7.2, Schedule 74
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$ (338)			$ -			$ 262	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011			2012			2013			
Line No.	Particulars	Revenue At 2011 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2011 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2011 Rates	Lag Days Service to Collection	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											
3	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.2, Schedule 14
4	Residential and Commercial	$ 170,916	38.7	$ 6,614,449	$ 172,335	38.7	$ 6,669,346	$ 173,894	38.7	$ 6,729,706	- Sect 7-TAB 7.2, Schedule 16
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	2,018	38.6	77,879	2,018	38.6	77,879	2,018	38.6	77,879	
6	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
7											
8	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	20,710	38.4	795,253	20,733	38.4	796,128	20,733	38.4	796,128	
9											
10	Total Gas Sales	193,644	38.7	7,487,581	195,085	38.7	7,543,353	196,645	38.7	7,603,713	
11	Other Revenues										
12	Royalty Revenue (FEVI)	17,283	45.6	788,118	-	45.6	-	-	45.6	-	- Sect 7-TAB 7.2, Schedule 4
13	Late Payment Charges	222	38.3	8,503	223	38.3	8,549	224	38.4	8,595	- Sect 7-TAB 7.2, Schedule 18 - 20
14	Returned Cheque Charges	3	43.3	130	3	43.3	130	3	43.3	130	- Sect 7-TAB 7.2, Schedule 18 - 20
15	Connection Charges	389	38.3	14,910	399	38.3	15,270	409	38.3	15,649	- Sect 7-TAB 7.2, Schedule 18 - 20
16	Other Utility Income	7,015	45.6	319,884	12,026	45.6	548,386	12,026	45.6	548,386	
17											
18											
19	Total Revenue	$ 218,556	39.4	$ 8,619,126	$ 207,736	39.1	$ 8,115,688	$ 209,307	39.1	$ 8,176,473	
20											
21											
22	**REVENUE, REVISED RATES**										
23											
24	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.2, Schedule 14
25	Residential and Commercial	$ 150,149	38.7	$ 5,810,766	$ 172,339	38.7	$ 6,669,501	$ 191,176	38.7	$ 7,398,520	- Sect 7-TAB 7.2, Schedule 16
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	1,815	38.6	70,047	2,018	38.6	77,879	2,176	38.6	83,976	
27	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
28											
29	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	20,710	38.4	795,253	20,733	38.4	796,128	20,733	38.4	796,128	
30											
31	Total Gas Sales	172,674	38.7	6,676,066	195,089	38.7	7,543,508	214,085	38.7	8,278,624	
32	Other Revenues										- Sect 7-TAB 7.2, Schedule 18 - 20
33	Royalty Revenue (FEVI)	17,283	45.6	788,118	-	45.6	-	-	45.6	-	- Sect 7-TAB 7.2, Schedule 18 - 20
34	Late Payment Charges	222	38.3	8,503	223	38.3	8,549	224	38.4	8,595	- Sect 7-TAB 7.2, Schedule 18 - 20
35	Returned Cheque Charges	3	43.3	130	3	43.3	130	3	43.3	130	
36	Connection Charges	389	38.3	14,910	399	38.3	15,270	409	38.3	15,649	
37	Other Utility Income	7,015	45.6	319,884	12,026	45.6	548,386	12,026	45.6	548,386	
38											
39											
40	Total Revenue	$ 197,586	39.5	$ 7,807,611	$ 207,740	39.1	$ 8,115,843	$ 226,747	39.0	$ 8,851,384	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars		2011 Amount	2011 Lead Days Expense to Payment	2011 Dollar Days	2012 Amount	2012 Lead Days Expense to Payment	2012 Dollar Days	2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**											
2												
3	Operating And Maintenance											
4	Expenses		$ 28,136	35.8	$ 1,007,269	$ 30,303	35.8	$ 1,084,847	$ 30,515	35.8	$ 1,092,437	- Sect 7-TAB 7.2, Schedule 4, 5, 6
5	Transportation Costs		4,480	40.2	180,096	4,483	40.2	180,217	4,494	40.2	180,659	- Sect 7-TAB 7.2, Schedule 4, 5, 6
6	Gas Purchases (excl Royalty Credits)		66,773	40.2	2,684,275	74,337	40.2	2,988,347	76,399	40.2	3,071,240	
7												
8	Taxes Other Than Income											- Sect 7-TAB 7.2, Schedule 24
9	Property Taxes		9,293	2.6	24,162	9,895	2.6	25,727	10,263	2.6	26,684	- Sect 7-TAB 7.2, Schedule 25
10	Carbon Tax		13,068	29.5	385,508	16,079	29.5	474,331	17,669	29.5	521,250	
11	HST - Net	*	2,316	39.8	92,162	5,593	39.8	222,591	5,638	39.8	224,377	
12	PST Component of HST (REC)	*	1,947	37.1	72,237	(1,294)	34.8	(45,031)	(1,288)	34.8	(44,815)	
13	Income Tax		9,210	15.2	139,992	3,877	15.2	58,930	3,082	15.2	46,846	- Sect 7-TAB 7.2, Schedule 30, 31, 32
14												
15	Total		$ 135,223	33.9	$ 4,585,701	$ 143,273	34.8	$ 4,989,959	$ 146,772	34.9	$ 5,118,678	
16												
17												
18	**EXPENSES, REVISED RATES**											
19												
20	Operating And Maintenance											
21	Expenses		$ 28,136	35.8	$ 1,007,269	$ 30,303	35.8	$ 1,084,847	$ 30,515	35.8	$ 1,092,437	- Sect 7-TAB 7.2, Schedule 4, 5, 6
22	Transportation Costs		4,480	40.2	180,096	4,483	40.2	180,217	4,494	40.2	180,659	- Sect 7-TAB 7.2, Schedule 4, 5, 6
23	Gas Purchases (excl Royalty Credits)		66,773	40.2	2,684,275	74,337	40.2	2,988,347	76,399	40.2	3,071,240	
24												
25	Taxes Other Than Income											- Sect 7-TAB 7.2, Schedule 24
26	Property Taxes		9,293	2.6	24,162	9,895	2.6	25,727	10,263	2.6	26,684	- Sect 7-TAB 7.2, Schedule 25
27	Carbon Tax		13,068	29.5	385,508	16,079	29.5	474,331	17,669	29.5	521,250	
28	HST - Net	*	2,065	39.8	82,206	5,593	39.8	222,591	6,137	39.8	244,252	
29	PST Component of HST (REC)	*	1,765	37.1	65,471	(1,294)	34.8	(45,031)	(1,427)	34.8	(49,658)	
30	Income Tax		3,655	15.2	55,556	3,878	15.2	58,946	7,440	15.2	113,088	- Sect 7-TAB 7.2, Schedule 30, 31, 32
31												
32	Total		$ 129,235	34.7	$ 4,484,543	$ 143,274	34.8	$ 4,989,975	$ 151,491	34.3	$ 5,199,952	
33	* 2011 was calculated using prior approved GST and PST method											

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Plant & Equipment						
2	Net Book Value *	$ (773,096)	$ (813,945)	$ (809,361)	$ (834,692)	$ (833,566)	
3	Less: Undepreciated Capital Cost	(577,983)	(610,463)	(595,607)	(607,875)	(595,405)	
4		(195,113)	(203,482)	(213,754)	(226,817)	(238,161)	
5	Weighted Average Future Tax Rate	24.99%	24.98%	25.00%	25.00%	25.00%	
6		(48,762)	(50,836)	(53,439)	(56,704)	(59,540)	
7							
8	Total FIT Liability- After Tax (PP&E)	(48,762)	(50,836)	(53,439)	(56,704)	(59,540)	
9	Total FIT Liability- After Tax (Non-PP&E)	919	1,040	744	613	636	
10	Total FIT Liability- After Tax	(47,843)	(49,795)	(52,695)	(56,091)	(58,904)	
11							
12	Tax Gross Up	(15,940)	(16,583)	(17,565)	(18,697)	(19,635)	
13							
14	FIT Liability/Asset - End of Year	(63,783)	(66,379)	(70,259)	(74,788)	(78,539)	
15							
16	FIT Liability/Asset - Opening Balance	(56,829)	(61,399)	(63,783)	(70,260)	(74,788)	
17							- Sect 7-TAB 7.2, Schedule 39
18	FIT Liability/Asset - Mid Year	(60,306)	(63,889)	(67,021)	(72,524)	(76,664)	- Sect 7-TAB 7.2, Schedule 40
19							- Sect 7-TAB 7.2, Schedule 41
20							
21	Note: * Excludes Land, Software CIAC, and WIP.						

($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 RATES							
2	Long-Term Debt		$ 365,526	53.99%	5.70%	3.08%	$ 20,837	- Sect 7-TAB 7.2, Schedule 82
3	Unfunded Debt		40,703	6.01%	3.25%	0.20%	1,323	
4	Common Equity		270,819	40.00%	15.68%	6.27%	42,476	
5								
6			$ 677,048	100.00%		9.55%	$ 64,636	- Sect 7-TAB 7.2, Schedule 39
7								
8								
9								
10	2011 COST OF SERVICE RATES - PROJECTED							
11	Long-Term Debt		$ 365,526	54.02%	5.70%	3.08%	$ 20,837	- Sect 7-TAB 7.2, Schedule 82
12	Unfunded Debt	$ 40,703						
13	Adjustment, Revised Rates	(203)	40,500	5.98%	3.25%	0.19%	1,316	
14	Common Equity		270,684	40.00%	10.00%	4.00%	27,068	
15								- Sect 7-TAB 7.2, Schedule 4
16			$ 676,710	100.00%		7.27%	$ 49,221	- Sect 7-TAB 7.2, Schedule 39

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2012 AT 2011 RATES							
2	Long-Term Debt		$ 365,526	46.39%	5.75%	2.67%	$ 21,003	- Sect 7-TAB 7.2, Schedule 83
3	Unfunded Debt		107,192	13.61%	4.25%	0.58%	4,556	
4	Common Equity		315,146	40.00%	9.98%	3.99%	31,512	
5								
6			$ 787,864	100.00%		7.24%	$ 57,071	- Sect 7-TAB 7.2, Schedule 40
7								
8								
9								
10	2012 COST OF SERVICE RATES - FORECAST							
11	Long-Term Debt		$ 365,526	46.39%	5.75%	2.67%	$ 21,003	- Sect 7-TAB 7.2, Schedule 83
12	Unfunded Debt	$ 107,192						
13	Adjustment, Revised Rates	-	107,192	13.61%	4.25%	0.58%	4,556	
14	Common Equity		315,146	40.00%	10.00%	4.00%	31,515	
15								- Sect 7-TAB 7.2, Schedule 5
16			$ 787,864	100.00%		7.24%	$ 57,074	- Sect 7-TAB 7.2, Schedule 40

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 AT 2011 RATES							
2	Long-Term Debt		$ 350,000	43.01%	5.85%	2.52%	$ 20,473	- Sect 7-TAB 7.2, Schedule 84
3	Unfunded Debt		138,290	16.99%	5.25%	0.89%	7,260	
4	Common Equity		325,526	40.00%	5.98%	2.39%	19,489	
5								
6			$ 813,816	100.00%		5.80%	$ 47,222	- Sect 7-TAB 7.2, Schedule 41
7								
8								
9								
10	2013 COST OF SERVICE RATES - FORECAST							
11	Long-Term Debt		$ 350,000	42.99%	5.85%	2.51%	$ 20,473	- Sect 7-TAB 7.2, Schedule 84
12	Unfunded Debt	$ 138,290						
13	Adjustment, Revised Rates	157	138,447	17.01%	5.25%	0.89%	7,268	
14	Common Equity		325,631	40.00%	10.00%	4.00%	32,563	
15								- Sect 7-TAB 7.2, Schedule 6
16			$ 814,078	100.00%		7.41%	$ 60,304	- Sect 7-TAB 7.2, Schedule 41

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
2	L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000	5.200%	100,000	5,200
3	PCEPA - 2011	1-Jan-2008	1-Jan-2013	2.341%	15,526	-	15,526	2.341%	15,526	364
4										
5	Total								$ 365,526	$ 20,837
6										
7									Average Embedded Cost	5.70%
8										
9	Cross Reference								- Sect 7-TAB 7.2, Schedule 79	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
2	L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000	5.200%	100,000	5,200
3	PCEPA - 2012	1-Jan-2008	1-Jan-2013	3.416%	15,526	-	15,526	3.416%	15,526	530
4										
5	Total								$ 365,526	$ 21,003
6										
7									Average Embedded Cost	5.75%
8										
9	Cross Reference								- Sect 7-TAB 7.2, Schedule 80	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
2	L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000	5.200%	100,000	5,200
3	PCEPA - 2013	1-Jan-2008	1-Jan-2013	4.413%	15,526	-	15,526	4.413%	-	-
4										
5	Total								$ 350,000	$ 20,473
6										
7									Average Embedded Cost	5.85%
8										
9	Cross Reference								- Sect 7-TAB 7.2, Schedule 81	

7.3 Whistler Schedules

Whistler

	2012 ($ thousands)		2013 ($ thousands)		Total ($ thousands)		Cross Reference
Volume/Revenue Related							
Customer Growth and Use Rates	$ 497.9		$ 77.0		$ 574.9		
Change in Other Revenue	40.4	538.3	-	77.0	40.4	615.3	
O&M Changes							
Gross O&M Increases	38.1		8.9		47.0		
Less: Capitalized Overhead	(5.3)	32.7	(1.3)	7.7	(6.6)	40.4	
Depreciation & Removal Cost Provision							
Change in Depreciation Rates	30.0		-		30.0		
Tax Expense Impact of Depreciation Changes	36.0		6.0		42.0		
Depreciation from Net Additions	2.7		16.0		18.7		
Removal Cost Provision	75.4	144.2	2.0	24.0	77.4	168.2	
Amortization Expense							
CIAC	(5.0)		-		(5.0)		
Deferral Accounts	(378.0)	(383.0)	581.0	581.0	203.0	198.0	
Other							
Property and Other Taxes	(42.4)		8.0		(34.4)		
Other (NSP Provision, Transportation Costs)	121.0		-		121.0		
Income Tax Rate Change	(27.8)		(16.5)		(44.2)		
Other Income Tax Changes	(104.7)		216.6		111.9		
Financing Rate Changes	(73.8)		48.8		(25.0)		
Financing Changes	(14.1)		(14.3)		(28.4)		
Rate Base Growth	(18.2)	(160.0)	(25.5)	217.2	(43.7)	57.2	
Revenue Deficiency (Surplus)		**$ 172.2**		**$ 906.9**		**$ 1,079.1**	- Sect 7-TAB 7.3, Schedule 2 & 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Non-Bypass Sales	2012 Non-Bypass Transportation	2012 Bypass and Special Rates	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 11,425	$ 11,209	$ -	$ -	$ 11,209	$ (216)	- Sect 7-TAB 7.3, Schedule 11
5								
6								
7	Total Revenue	11,425	11,209	-	-	11,209	(216)	
8								
9	Less - Cost of Gas	(3,562)	(3,493)	-	-	(3,493)	69	- Sect 7-TAB 7.3, Schedule 13
10								
11	Gross Margin	$ 7,863	$ 7,716	$ -	$ -	$ 7,716	$ (147)	
12								
13	Revenue Deficiency (Surplus)	$ -	$ 172	$ -	$ -	**$ 172**	$ 172	
14								
15	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	2.23%	0.00%	0.00%	2.23%		
16								
17	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	1.53%	0.00%	0.00%	1.53%		
18								

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Non-Bypass Sales	2013 Non-Bypass Transportation	2013 Bypass and Special Rates	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 11,209	$ 11,094	$ -	$ -	$ 11,094	$ (115)	- Sect 7-TAB 7.3, Schedule 12
5								
6								
7	Total Revenue	11,209	11,094	-	-	11,094	(115)	
8								
9	Less - Cost of Gas	(3,493)	(3,455)	-	-	(3,455)	38	- Sect 7-TAB 7.3, Schedule 13
10								
11	Gross Margin	$ 7,716	$ 7,639	$ -	$ -	$ 7,639	$ (77)	
12								
13	Revenue Deficiency (Surplus)	$ 172	$ 1,079	$ -	$ -	**$ 1,079**	$ 907	
14								
15	Revenue Deficiency (Surplus) as a % of Gross Margin	2.23%	14.12%	0.00%	0.00%	14.12%		
16								
17	Revenue Deficiency (Surplus) as a % of Total Revenue	1.53%	9.73%	0.00%	0.00%	9.73%		
18								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	ENERGY VOLUMES (TJ)					
2	Sales	765	764	731	(33)	- Sect 7-TAB 7.3, Schedule 7
3		765	764	731	(33)	
4						
5	Average Rate per GJ					
6	Sales	$ 17.945	$ 17.439	$ 15.629	$ (1.810)	
7	Average	$ 18.314	$ 17.439	$ 16.055	$ (1.384)	
8						
9	UTILITY REVENUE					
10	Sales - Existing Rates	$ 13,737	$ 17,825	$ 11,425	$ (6,400)	- Sect 7-TAB 7.3, Schedule 10
11	- Increase / (Decrease)	-	(4,497)	-	4,497	
12	RSAM Revenue	283	-	311	311	
13	Transportation - Existing Rates	-	-	-	-	- Sect 7-TAB 7.3, Schedule 10
14	- Increase / (Decrease)	-	-	-	-	
15	**Total Revenue**	14,019	13,328	11,736	(1,592)	
16						
17	Cost of Gas Sold (Including Gas Lost)	5,165	5,114	3,562	(1,552)	- Sect 7-TAB 7.3, Schedule 13
18						
19	**Gross Margin**	8,854	8,214	8,174	(40)	
20						
21	Operation and Maintenance	654	747	747	0	- Sect 7-TAB 7.3, Schedule 21
22	Transportation Costs	2,430	2,458	2,585	127	
23	Property and Sundry Taxes	285	278	278	(0)	- Sect 7-TAB 7.3, Schedule 24
24	Depreciation and Amortization	1,863	1,337	1,306	(31)	- Sect 7-TAB 7.3, Schedule 27
25	NSP Provisions	(6)	6	6	-	
26	Other Operating Revenue	(30)	(56)	(16)	40	- Sect 7-TAB 7.3, Schedule 18
27	Sub-total	5,196	4,770	4,906	136	
28	Utility Income Before Income Taxes	3,658	3,444	3,268	(176)	
29						
30	Income Taxes	671	432	358	(74)	- Sect 7-TAB 7.3, Schedule 30
31						
32	**EARNED RETURN**	$ 2,987	$ 3,012	$ 2,910	$ (102)	- Sect 7-TAB 7.3, Schedule 30
33	VINGPA Adjustment (ends December 31, 2011)	-	-	-	-	
34	**EARNED RETURN**	$ 2,987	$ 3,012	$ 2,909	$ (103)	- Sect 7-TAB 7.3, Schedule 79
35				-		
36						
37	**UTILITY RATE BASE**	$ 45,400	$ 42,594	$ 44,891	$ 2,297	- Sect 7-TAB 7.3, Schedule 39
38						
39	**RATE OF RETURN ON UTILITY RATE BASE**	6.58%	7.07%	6.48%	-0.59%	- Sect 7-TAB 7.3, Schedule 79

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars (1)	2011 PROJECTED (2)	2012 Existing 2011 Rates (3)	2012 Revised Rates Revised Revenue (4)	2012 Revised Rates Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	731	716	-	716	(15)	- Sect 7-TAB 7.3, Schedule 8
3		731	716	-	716	(15)	
4							
5	Average Rate per GJ						
6	Sales	$ 15.629	$ 15.655	$ -	$ 15.895	$ 0.266	
7	Average	$ 16.055	$ 15.655	$ -	$ 15.895	$ (0.160)	
8							
9	UTILITY REVENUE						
10	Sales - Existing Rates	$ 11,425	$ 11,209	$ -	$ 11,209	$ (216)	- Sect 7-TAB 7.3, Schedule 11
11	- Increase / (Decrease)	-	-	172	172	172	- Sect 7-TAB 7.3, Schedule 14
12						-	
13	Transportation - Existing Rates	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 11
14	- Increase / (Decrease)	-		-	-	-	- Sect 7-TAB 7.3, Schedule 14
15	**Total Revenue**	11,736	11,209	172	11,381	(355)	
16							
17	Cost of Gas Sold (Including Gas Lost)	3,562	3,493	-	3,493	(69)	- Sect 7-TAB 7.3, Schedule 13
18							
19	**Gross Margin**	8,174	7,716	172	7,888	(286)	
20							
21	Operation and Maintenance	747	779	-	779	32	- Sect 7-TAB 7.3, Schedule 21
22	Transportation Costs	2,585	2,585	-	2,585	-	
23	Property and Sundry Taxes	278	236	-	236	(42)	- Sect 7-TAB 7.3, Schedule 25
24	Depreciation and Amortization	1,306	1,062	-	1,062	(244)	- Sect 7-TAB 7.3, Schedule 28
25	NSP Provisions	6	-	-	-	(6)	
26	Other Operating Revenue	(16)	(16)	-	(16)	-	- Sect 7-TAB 7.3, Schedule 19
27	Sub-total	4,906	4,646	-	4,646	(260)	
28	Utility Income Before Income Taxes	3,268	3,070	172	3,242	(26)	
29							
30	Income Taxes	358	293	43	336	(22)	- Sect 7-TAB 7.3, Schedule 31
31							
32	**EARNED RETURN**	$ 2,910	$ 2,777	$ 129	$ 2,906	$ (4)	- Sect 7-TAB 7.3, Schedule 31
33	VINGPA Adjustment (ends December 31, 2011)	-	-	-	-	-	
34	**EARNED RETURN**	$ 2,909	$ 2,777	$ 129	$ 2,906	$ (3)	- Sect 7-TAB 7.3, Schedule 80
35							
36							
37	**UTILITY RATE BASE**	$ 44,891	$ 42,136	$ 3	$ 42,139	$ (2,752)	- Sect 7-TAB 7.3, Schedule 40
38							
39	**RATE OF RETURN ON UTILITY RATE BASE**	6.48%	6.59%		6.90%	0.42%	- Sect 7-TAB 7.3, Schedule 80

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Revised Rates Revised Revenue	2013 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	716	709	-	709	(7)	- Sect 7-TAB 7.3, Schedule 9
3		716	709	-	709	(7)	
4							
5	Average Rate per GJ						
6	Sales	$ 15.895	$ 15.647	$ -	$ 17.169	$ 1.274	
7	Average	$ 15.895	$ 15.647	$ -	$ 17.169	$ 1.274	
8							
9	UTILITY REVENUE						
10	Sales - Existing Rates	$ 11,209	$ 11,094	$ -	$ 11,094	$ (115)	- Sect 7-TAB 7.3, Schedule 12
11	- Increase / (Decrease)	172	-	1,079	1,079	907	- Sect 7-TAB 7.3, Schedule 16
12						-	
13	Transportation - Existing Rates	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 12
14	- Increase / (Decrease)	-		-	-	-	- Sect 7-TAB 7.3, Schedule 16
15	**Total Revenue**	11,381	11,094	1,079	12,173	792	
16							
17	Cost of Gas Sold (Including Gas Lost)	3,493	3,455	-	3,455	(38)	- Sect 7-TAB 7.3, Schedule 13
18							
19	**Gross Margin**	7,888	7,639	1,079	8,718	830	
20							
21	Operation and Maintenance	779	787	-	787	8	- Sect 7-TAB 7.3, Schedule 21
22	Transportation Costs	2,585	2,585	-	2,585	-	
23	Property and Sundry Taxes	236	244	-	244	8	- Sect 7-TAB 7.3, Schedule 26
24	Depreciation and Amortization	1,062	1,661	-	1,661	599	- Sect 7-TAB 7.3, Schedule 29
25	NSP Provisions	-	-	-	-	-	
26	Other Operating Revenue	(16)	(16)	-	(16)	-	- Sect 7-TAB 7.3, Schedule 20
27	Sub-total	4,646	5,261	-	5,261	615	
28	Utility Income Before Income Taxes	3,242	2,378	1,079	3,457	215	
29							
30	Income Taxes	336	272	270	542	206	- Sect 7-TAB 7.3, Schedule 32
31							
32	**EARNED RETURN**	$ 2,906	$ 2,106	$ 809	$ 2,915	$ 9	- Sect 7-TAB 7.3, Schedule 32
33	VINGPA Adjustment (ends December 31, 2011)	-	-	-	-	-	
34	**EARNED RETURN**	$ 2,906	$ 2,106	$ 809	$ 2,915	$ 9	- Sect 7-TAB 7.3, Schedule 81
35							
36							
37	**UTILITY RATE BASE**	$ 42,139	$ 41,483	$ 19	$ 41,502	$ (637)	- Sect 7-TAB 7.3, Schedule 41
38							
39	**RATE OF RETURN ON UTILITY RATE BASE**	6.90%	5.08%		7.02%	0.13%	- Sect 7-TAB 7.3, Schedule 81

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Projected Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	SGS 1/2 RES	224.1	210.6	230.3	-	230.3	19.7	
3	SGS 1/2 COMM	58.9	45.3	65.9		65.9	20.6	
4	LGS 1	131.2	104.8	134.2		134.2	29.4	
5								
6	Residential & Commercial	414.3	360.7	430.4	-	430.4	69.7	
7								
8	LGS 2	140.9	162.2	129.7		129.7	(32.5)	
9	LGS 3	210.2	241.4	170.4		170.4	(71.0)	
10								
11	**TOTAL SALES AND TRANSPORTATION SERVICES**	765.5	764.3	730.5	-	730.5	(33.8)	- Sect 7-TAB 7.3, Schedule 4

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars	2011 PROJECTED	2012 Projected Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	SGS 1/2 RES	230.3	236.9	-	236.9	6.6	
3	SGS 1/2 COMM	65.9	74.9		74.9	9.0	
4	LGS 1	134.2	139.6		139.6	5.4	
5							
6	Residential & Commercial	430.4	451.4	-	451.4	21.0	
7							
8	LGS 2	129.7	122.5		122.5	(7.2)	
9	LGS 3	170.4	142.1		142.1	(28.3)	
10							
11	**TOTAL SALES AND TRANSPORTATION SERVICES**	730.5	716.0	-	716.0	(14.5)	- Sect 7-TAB 7.3, Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 FORECAST	2013 Projected Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	SGS 1/2 RES	236.9	243.6	-	243.6	6.7	
3	SGS 1/2 COMM	74.9	85.2		85.2	10.3	
4	LGS 1	139.6	145.3		145.3	5.7	
5							
6	Residential & Commercial	451.4	474.1	-	474.1	22.7	
7							
8	LGS 2	122.5	115.7		115.7	(6.8)	
9	LGS 3	142.1	118.7		118.7	(23.4)	
10							
11	**TOTAL SALES AND TRANSPORTATION SERVICES**	716.0	708.5	-	708.5	(7.5)	- Sect 7-TAB 7.3, Schedule 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2011 APPROVED	2011 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
						(Column (5) - Column (2))	
1	**SALES**						
2	SGS 1/2 RES	$ 5,052	$ 3,733	$ -	$ 3,733	$ (1,319)	
3	SGS 1/2 COMM	1,058	1,024		1,024	(34)	
4	LGS 1	2,420	2,065		2,065	(355)	
5	Residential & Commercial	8,530	6,822	-	6,822	(1,708)	
6							
7	LGS 2	3,737	1,991	-	1,991	(1,746)	
8	LGS 3	5,557	2,612		2,612	(2,945)	
9		9,295	4,603	-	4,603	(4,692)	
10							
11	TOTAL SALES AND TRANSPORTATION SERVICES	$ 17,825	$ 11,425	$ -	$ 11,425	$ (6,400)	- Sect 7-TAB 7.3, Schedule 4

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	SGS 1/2 RES	$ 3,733	$ 3,834	$ -	$ 3,834	$ 101	
3	SGS 1/2 COMM	1,024	1,165		1,165	141	
4	LGS 1	2,065	2,147		2,147	82	
5	Residential & Commercial	6,822	7,146	-	7,146	324	
6							
7	LGS 2	1,991	1,881	-	1,881	(110)	
8	LGS 3	2,612	2,182		2,182	(430)	
9		4,603	4,063	-	4,063	(540)	
10							- Sect 7-TAB 7.3, Schedule 5
11	TOTAL SALES AND TRANSPORTATION SERVICES	$ 11,425	$ 11,209	$ -	$ 11,209	$ (216)	- Sect 7-TAB 7.3, Schedule 15

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Gas Sales Revenue At Existing 2011 Rates Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	SGS 1/2 RES	$ 3,834	$ 3,939	$ -	$ 3,939	$ 105	
3	SGS 1/2 COMM	1,165	1,324		1,324	159	
4	LGS 1	2,147	2,232		2,232	85	
5	Residential & Commercial	7,146	7,495	-	7,495	349	
6							
7	LGS 2	1,881	1,777	-	1,777	(104)	
8	LGS 3	2,182	1,822		1,822	(360)	
9		4,063	3,599	-	3,599	(464)	
10							- Sect 7-TAB 7.3, Schedule 6
11	TOTAL SALES AND TRANSPORTATION SERVICES	$ 11,209	$ 11,094	$ -	$ 11,094	$ (115)	- Sect 7-TAB 7.3, Schedule 17

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011 Gas Costs			2012 Gas Costs			2013 Gas Costs		
Line No.	Particulars	Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Non-Bypass Sales & Transp	Bypass and Special Rates	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**SALES**									
2	SGS 1/2 RES	1,123	$ -	$ 1,123	$ 1,155	$ -	$ 1,155	1,188	$ -	$ 1,188
3	SGS 1/2 COMM	321		321	366		366	416		416
4	LGS 1	655		655	681		681	708		708
5										
6	Residential & Commercial	2,099	-	2,099	2,202	-	2,202	2,312	-	2,312
7										
8	LGS 2	632		632	597		597	564		564
9	LGS 3	831		831	694		694	579		579
10										
11		1,463	-	1,463	1,291	-	1,291	1,143	-	1,143
12										
13	TOTAL SALES AND TRANSPORTATION SERVICES	$ 3,562	$ -	$ 3,562	$ 3,493	$ -	$ 3,493	$ 3,455	$ -	$ 3,455
14										
15	Cross Reference			- Sect 7-TAB 7.3, Schedule 4			- Sect 7-TAB 7.3, Schedule 5			- Sect 7-TAB 7.3, Schedule 6

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Effective Increase / (Decrease) 2.23% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000s)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ------ Revised Rates ------- Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	SGS 1/2 RES	236.9	$ 16.648	$ 3,834	$ 11.633	$ 2,679	$ 0.248	$ 57	2,278	$ 16.896	$ 3,891
4	SGS 1/2 COMM	74.9	17.678	1,165	12.124	799	0.273	18	179	17.951	1,183
5	LGS 1	139.6	15.999	2,147	10.924	1,466	0.253	34	81	16.252	2,181
6	Residential & Commercial	451.4		7,146		4,944		109	2,538		7,255
7											
8	LGS 2	122.5	14.503	1,881	9.892	1,283	0.224	29	49	14.727	1,910
9	LGS 3	142.1	12.805	2,182	8.732	1,488	0.200	34	23	13.005	2,216
10											
11	Total Non-Bypass Sales & Transportation Service	716.0		$ 11,209		$ 7,715		$ 172	2,610		$ 11,381
12											
13	Cross Reference	- Sect 7-TAB 7.3, Schedule 8		- Sect 7-TAB 7.3, Schedule 11				- Sect 7-TAB 7.3, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 2.23% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	-	-	-	-
6	Burrard Thermal - Firm	-	-	-	-	-	-	-	-	-	-
7	FEVI - Firm	-	-	-	-	-	-	-	-	-	-
8	BC Hydro and ICP	-	-	-	-	-	-	-	-	-	-
9	VIGJV	-	-	-	-	-	-	-	-	-	-
10	FEW	-	-	-	-	-	-	-	-	-	-
11	Squamish	-	-	-	-	-	-	-	-	-	-
12	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
13	Schedule 25 - Firm Service	-	-	-	-	-	-	-	-	-	-
14	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
15	Total Bypass and Spec. Rates T-Svc	-		-		-		-	-		-
16											
17	TOTAL NON-BYPASS AND BYPASS SALES AND										
18	TRANSPORTATION SERVICE	716.0		$ 11,209		$ 7,715		$ 172	2,610		$ 11,381
19											
20	Cross Reference	- Sect 7-TAB 7.3, Schedule 8		- Sect 7-TAB 7.3, Schedule 11				- Sect 7-TAB 7.3, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) 14.12% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	SGS 1/2 RES	243.6	$ 17.104	$ 3,939	$ 11.945	$ 2,751	$ 1.611	$ 371	2,292	$ 18.715	$ 4,310
4	SGS 1/2 COMM	85.2	20.091	1,324	13.778	908	1.973	130	184	22.064	1,454
5	LGS 1	145.3	16.632	2,232	11.356	1,524	1.647	221	81	18.279	2,453
6	Residential & Commercial	474.1		7,495		5,183		722	2,557		8,217
7											
8	LGS 2	115.7	13.701	1,777	9.345	1,212	1.357	176	49	15.058	1,953
9	LGS 3	118.7	10.692	1,822	7.295	1,243	1.062	181	23	11.754	2,003
10											
11	Total Non-Bypass Sales & Transportation Service	708.5		$ 11,094		$ 7,638		$ 1,079	2,629		$ 12,173
12											
13	Cross Reference	- Sect 7-TAB 7.3, Schedule 9		- Sect 7-TAB 7.3, Schedule 12				- Sect 7-TAB 7.3, Schedule 3			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue -- At Existing 2011 Rates -- Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Gross Margin -- At Existing 2011 Rates -- Margin ($000s)	Increase / (Decrease) 14.12% of Margin $/GJ	Increase / (Decrease) 14.12% of Margin Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ------ Revised Rates ------- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	$ -
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	-	-	-	-
6	Burrard Thermal - Firm	-	-	-	-	-	-	-	-	-	-
7	FEVI - Firm	-	-	-	-	-	-	-	-	-	-
8	BC Hydro and ICP	-	-	-	-	-	-	-	-	-	-
9	VIGJV	-	-	-	-	-	-	-	-	-	-
10	FEW	-	-	-	-	-	-	-	-	-	-
11	Squamish	-	-	-	-	-	-	-	-	-	-
12	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
13	Schedule 25 - Firm Service	-	-	-	-	-	-	-	-	-	-
14	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
15	Total Bypass and Spec. Rates T-Svc	-		-		-		-	-		-
16											
17	TOTAL NON-BYPASS AND BYPASS SALES AND										
18	TRANSPORTATION SERVICE	708.5		$ 11,094		$ 7,638		$ 1,079	2,629		$ 12,173
19											
20	Cross Reference	- Sect 7-TAB 7.3, Schedule 9		- Sect 7-TAB 7.3, Schedule 12				- Sect 7-TAB 7.3, Schedule 3			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 19	$ 49	$ 11	$ (38)	- Sect 7-TAB 7.3, Schedule 76
4						
5	Connection Charge	4	5	4	(1)	- Sect 7-TAB 7.3, Schedule 76
6						
7	NSF Returned Cheque Charges	0	-	-	-	- Sect 7-TAB 7.3, Schedule 76
8						
9	Other Recoveries	6	2	1	(1)	- Sect 7-TAB 7.3, Schedule 76
10						
11	**Total Other Operating Revenue**	$ 30	$ 56	$ 16	$ (40)	- Sect 7-TAB 7.3, Schedule 4

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 11	$ 11	$ -	- Sect 7-TAB 7.3, Schedule 76
4					
5	Connection Charge	4	4	-	- Sect 7-TAB 7.3, Schedule 76
6					
7	NSF Returned Cheque Charges	-	-	-	- Sect 7-TAB 7.3, Schedule 76
8					
9	Other Recoveries	1	1	-	- Sect 7-TAB 7.3, Schedule 76
10					
11	**Total Other Operating Revenue**	$ 16	$ 16	$ -	- Sect 7-TAB 7.3, Schedule 5

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 11	$ 11	$0	- Sect 7-TAB 7.3, Schedule 76
4					
5	Connection Charge	4	4	-	- Sect 7-TAB 7.3, Schedule 76
6					
7	NSF Returned Cheque Charges	-	-	-	- Sect 7-TAB 7.3, Schedule 76
8					
9	Other Recoveries	1	1	-	- Sect 7-TAB 7.3, Schedule 76
10					
11	**Total Other Operating Revenue**	$ 16	$ 16	$ -	- Sect 7-TAB 7.3, Schedule 6

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 59	$ 86	$ 15	$ 14	$ 14	
2	COPE Costs	1	-	-	-	-	
3	IBEW Costs	212	172	187	227	221	
4							
5	**Labour Costs**	**272**	**257**	**202**	**240**	**235**	
6							
7	Vehicle Costs	28	41	32	25	24	
8	Employee Expenses	(17)	14	9	4	5	
9	Materials and Supplies	21	14	12	31	30	
10	Computer Costs	1	1	-	3	4	
11	Fees and Administration Costs [1]	289	70	320	381	383	
12	Contractor Costs [1]	133	158	240	160	173	
13	Facilities	59	60	72	74	75	
14	Recoveries & Revenue	(14)	(9)	(20)	(13)	(14)	
15							
16	**Non-Labour Costs**	**501**	**350**	**667**	**666**	**680**	
17							
18							
19	**Total Gross O&M Expenses**	**773**	**607**	**868**	**906**	**915**	
20							
21	Add: Shared Corporate Services	-	261	-	-	-	
22	Add: PST Savings	-	-	(0)	0	(0)	
23	Less: Capitalized Overhead	(119)	(122)	(122)	(127)	(128)	
24							- Sect 7-TAB 7.3, Schedule 4
25	**Total O&M Expenses**	**$ 654**	**$ 747**	**$ 747**	**$ 779**	**$ 787**	- Sect 7-TAB 7.3, Schedule 5
							- Sect 7-TAB 7.3, Schedule 6

[1] 2012 and 2013 reflect customer service costs previously contracted

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 170	$ 178	$ 177	$ 104	$ 113	
2								
3	Operation Centre - Distribution	100-21	11	32	33	19	19	
4	Asset Management - Distribution	100-22	-	-	-	-	-	
5	Preventative Maintenance - Distribution	100-23	7	14	10	27	9	
6	Distribution Operations - General	100-24	64	111	101	104	105	
7	Meter Exchange	100-25	-	20	-	-	-	
8	Emergency Management	100-26	57	62	68	70	80	
9	Distribution Operations Total	100-20	138	240	213	220	212	
10								
11	Distribution Corrective - Meters	100-31	23	14	11	27	27	
12	Distribution Corrective - Propane	100-32	2	-	-	-	-	
13	Distribution Corrective - Leak Repair	100-33	17	4	6	30	30	
14	Distribution Corrective - Stations	100-34	4	-	2	4	4	
15	Distribution Corrective - General	100-35	2	2	2	1	1	
16	Distribution Maintenance Total	100-30	46	20	21	62	62	
17								
18	**Distribution Total**	**100**	**354**	**439**	**411**	**387**	**387**	
19								
20	Measurement Operations	400-11	9	-	19	22	22	
21	Measurement Maintenance	400-21	-	-	-	-	-	
22								
23	**Measurement Total**	**400**	**9**	**-**	**19**	**22**	**22**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1								
2	Customer Care - Supervision	700-10	-	-	-	-	-	
3	Customer Contact	700-20	27	25	156	146	154	
4	Bad Debt Management and Administration	700-30	21	12	21	21	21	
5	Customer Management & Sales	700-40	-	-	-	-	-	
6	**Customer Care Total**	**700**	**48**	**36**	**177**	**167**	**175**	
7								
8								
9	Administration & General	900-11	110	132	49	63	67	
10	Insurance	900-12	-	-	-	-	-	
11	Finance and Regulatory Affairs	900-13	-	-	-	-	-	
12	Shared Services Agreement	900-14	251	261	212	267	264	
13	Corporate Administration Total	900-10	361	393	261	330	331	
14	Forecasting	900-20	-	-	-	-	-	
15	Public Affairs	900-30	-	-	-	-	-	
16	Business Development	900-40	-	-	-	-	-	
17	Human Resources	900-50	-	-	-	-	-	
18	Other Post Employment Benefits (OPEB)	900-60	-	-	-	-	-	
19	**Administration & General Total**	**900**	**361**	**393**	**261**	**330**	**331**	
20								
21	**Total Gross O&M Expenses**		**773**	**868**	**868**	**906**	**915**	
22								
23	Add: PST Savings		-	-	(0)	0	(0)	
24	Less: Capitalized Overhead		(119)	(122)	(122)	(127)	(128)	
25								- Sect 7-TAB 7.3, Schedule 4
26	**Total O&M Expenses**		**$ 654**	**$ 747**	**$ 747**	**$ 779**	**$ 787**	- Sect 7-TAB 7.3, Schedule 5
27								- Sect 7-TAB 7.3, Schedule 6

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Total Expenses	2011 PROJECTED Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 170	$ 160	$ 160	$ 160	$ 0	
4							
5	General, School and Other	115	119	174	174	55	
6							
7		285	278	334	334	56	
8							
9	Add / Less: Deferred Property Taxes	-	-	(56)	(56)	(56)	
10							
11	Total	$ 285	$ 278	$ 278	$ 278	$ (0)	- Sect 7-TAB 7.3, Schedule 4

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Total Expenses	2012 Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 160	$ 120	$ 120	$ (40)	
4						
5	General, School and Other	174	116	116	(58)	
6						
7		334	236	236	(98)	
8						
9	Add / Less: Deferred Property Taxes	(56)	-	-	56	
10						
11	Total	$ 278	$ 236	$ 236	$ (42)	- Sect 7-TAB 7.3, Schedule 5

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars (1)	2012 FORECAST (2)	2013 Total Expenses (3)	2013 Revised Rates, Total Expenses (4)	Change (5)	Cross Reference (6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 120	$ 120	$ 120	$ -	
4						
5	General, School and Other	116	124	124	8	
6						
7		236	244	244	8	
8						
9	Add / Less: Deferred Property Taxes	-	-	-	-	
10						
11	Total	$ 236	$ 244	$ 244	$ 8	- Sect 7-TAB 7.3, Schedule 6

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 353	$ 392	$ 366	$ (26)	- Sect 7-TAB 7.3, Schedule 54
4						
5	Less: Amortization of Contributions in Aid of Construction	(5)	-	(5)	(5)	- Sect 7-TAB 7.3, Schedule 63
6		349	392	361	(31)	
7						
8	Add: Removal Cost Provision	5	5	5	-	- Sect 7-TAB 7.3, Schedule 4
9		353	397	366	(31)	- Sect 7-TAB 7.3, Schedule 33
10						
11	**Amortization Expense**					
12						
13	Amortization of Deferred Charges	1,509	940	940	0	- Sect 7-TAB 7.3, Schedule 67
14						
15	TOTAL	$ 1,863	$ 1,337	$ 1,306	$ (31)	- Sect 7-TAB 7.3, Schedule 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 366	$ 425	$ 59	- Sect 7-TAB 7.3, Schedule 57
4					
5	Less: Amortization of Contributions in Aid of Construction	(5)	(5)	-	- Sect 7-TAB 7.3, Schedule 64
6		361	420	59	
7					
8	Add: Removal Cost Provision	5	80	75	- Sect 7-TAB 7.3, Schedule 5
9		366	500	134	- Sect 7-TAB 7.3, Schedule 34
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	940	562	(378)	- Sect 7-TAB 7.3, Schedule 69
14					
15	TOTAL	$ 1,306	$ 1,062	$ (244)	- Sect 7-TAB 7.3, Schedule 5

FORTISBC ENERGY (Whistler) INC.

May 4, 2011 Section 7
TAB 7.3
Schedule 29

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 425	$ 441	$ 16	- Sect 7-TAB 7.3, Schedule 60
4					
5	Less: Amortization of Contributions in Aid of Construction	(5)	(5)	-	- Sect 7-TAB 7.3, Schedule 65
6		420	436	16	
7					
8	Add: Removal Cost Provision	80	82	2	- Sect 7-TAB 7.3, Schedule 6
9		500	518	18	- Sect 7-TAB 7.3, Schedule 35
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	562	1,143	581	- Sect 7-TAB 7.3, Schedule 71
14					
15	TOTAL	$ 1,062	$ 1,661	$ 599	- Sect 7-TAB 7.3, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing Rates	------ Revised Rates ------- Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 2,987	$ 3,012	$ 2,909	$ -	$ 2,910	$ (102)	- Sect 7-TAB 7.3, Schedule 4
3	Deduct - Interest on Debt	(1,232)	(1,308)	(1,379)	-	(1,379)	(71)	- Sect 7-TAB 7.3, Schedule 79
4	Accounting Income After Tax	1,755	1,704	1,530	-	1,531	(173)	
5	Net Additions (Deductions)	(72)	(505)	(536)	-	(536)	(31)	- Sect 7-TAB 7.3, Schedule 33
6	Adjusted Taxable Income After Tax	$ 1,683	$ 1,199	$ 994	$ -	$ 995	$ (204)	
7								
8	Current Income Tax Rate	28.50%	26.50%	26.50%	26.50%	26.50%	0.00%	
9	1 - Current Income Tax Rate	71.50%	73.50%	73.50%	73.50%	73.50%	0.00%	
10								
11								
12	Taxable Income	$ 2,354	$ 1,632	$ 1,352	$ -	$ 1,354	$ (278)	
13								
14								
15	Income Tax - Current	$ 671	$ 432	$ 358	$ -	$ 359	$ (73)	
16								
17	**Total Income Tax**	$ 671	$ 432	$ 358	$ -	$ 359	$ (73)	- Sect 7-TAB 7.3, Schedule 4
18								

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing Rates	2012 Revised Rates Revised Revenue	2012 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 2,910	$ 2,777	$ 129	$ 2,906	$ (4)	- Sect 7-TAB 7.3, Schedule 5
3	Deduct - Interest on Debt	(1,379)	(1,220)	-	(1,220)	159	- Sect 7-TAB 7.3, Schedule 80
4	Accounting Income After Tax	1,531	1,557	129	1,686	155	
5	Net Additions (Deductions)	(536)	(677)	-	(677)	(141)	- Sect 7-TAB 7.3, Schedule 34
6	Adjusted Taxable Income After Tax	$ 995	880	$ 129	$ 1,009	14	
7							
8	Current Income Tax Rate	26.50%	25.00%	25.00%	25.00%	-1.50%	
9	1 - Current Income Tax Rate	73.50%	75.00%	75.00%	75.00%	1.50%	
10							
11							
12	Taxable Income	1,353	$ 1,173	$ 172	$ 1,345	$ (8)	
13							
14							
15	Income Tax - Current	$ 359	$ 293	$ 43	$ 336	$ (23)	
16							
17	**Total Income Tax**	$ 359	$ 293	$ 43	$ 336	$ (23)	- Sect 7-TAB 7.3, Schedule 5
18							

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing Rates	2013 ------ Revised Rates ------- Revised Revenue	2013 ------ Revised Rates ------- Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 2,906	$ 2,106	$ 809	$ 2,915	$ 9	- Sect 7-TAB 7.3, Schedule 6
3	Deduct - Interest on Debt	(1,220)	(1,254)	(1)	(1,255)	(35)	- Sect 7-TAB 7.3, Schedule 81
4	Accounting Income After Tax	1,686	852	808	1,660	(26)	
5	Net Additions (Deductions)	(677)	(34)	-	(34)	643	- Sect 7-TAB 7.3, Schedule 35
6	Adjusted Taxable Income After Tax	$ 1,009	818	$ 808	$ 1,626	617	
7							
8	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
9	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
10							
11							
12	Taxable Income	1,345	$ 1,091	$ 1,077	$ 2,168	$ 823	
13							
14							
15	Income Tax - Current	$ 336	$ 273	$ 269	$ 542	$ 206	
16							
17	**Total Income Tax**	$ 336	$ 273	$ 269	$ 542	$ 206	- Sect 7-TAB 7.3, Schedule 6
18							

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 2	$ 5	$ 2	$ (3)	
3	Depreciation	353	397	366	(31)	- Sect 7-TAB 7.3, Schedule 27
4	Amortization of Decommissioning of Propane Assets	-	225	225	0	
5	Amortization of 75% Capital Contribution Costs	-	256	256	-	
6	Amortization of 75% Direct Appliance Conversion Costs	-	290	316	26	
7	Unpaid Remuneration	4	-	-	-	
8						
9	**Deductions:**					
10	Amortization of Deferred Charges	1,509	940	940	-	- Sect 7-TAB 7.3, Schedule 27
11	Less: Amortization of Decommissioning of Propane Assets (TGW)	-	(225)	(225)	(0)	
12	Less: Amortization of 75% Capital Contribution Costs (FEW)	-	(256)	(256)	-	
13	Less: Amortization of 75% Direct Appliance Conversion Costs (FEW)	-	(290)	(316)	(26)	
14	Capital Cost Allowance	(627)	(649)	(624)	25	- Sect 7-TAB 7.3, Schedule 36
15	Cumulative Eligible Capital Allowance	(1,228)	(1,119)	(1,142)	(23)	
16	Debt Issue Costs	-	-	-	-	
17	Overheads Capitalized Expensed for Tax Purposes	(82)	(78)	(78)	0	
18	Removal Costs	-	-	-	-	
19	Major Inspection Costs	-	-	-	-	
20	Taxable Capital Gain	0	-	-	-	
21						
22	TOTAL	$ (72)	$ (505)	$ (536)	$ (31)	- Sect 7-TAB 7.3, Schedule 30

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 2	$ 2	$ -	
3	Depreciation	366	500	134	- Sect 7-TAB 7.3, Schedule 28
4	Amortization of Decommissioning of Propane Assets	225	232	7	
5	Amortization of 75% Capital Contribution Costs	256	217	(39)	
6	Amortization of 75% Direct Appliance Conversion Costs	316	331	14	
7	Unpaid Remuneration	-	-	-	
8					
9	**Deductions:**				
10	Amortization of Deferred Charges	940	562	(378)	- Sect 7-TAB 7.3, Schedule 28
11	Less: Amortization of Decommissioning of Propane Assets (TGW)	(225)	(232)	(7)	
12	Less: Amortization of 75% Capital Contribution Costs (FEW)	(256)	(217)	39	
13	Less: Amortization of 75% Direct Appliance Conversion Costs (FEW)	(316)	(331)	(14)	
14	Capital Cost Allowance	(624)	(722)	(98)	- Sect 7-TAB 7.3, Schedule 37
15	Cumulative Eligible Capital Allowance	(1,142)	(931)	211	
16	Debt Issue Costs	-	-	-	
17	Overheads Capitalized Expensed for Tax Purposes	(78)	(82)	(4)	
18	Removal Costs	-	(6)	(6)	
19	Major Inspection Costs	-	-	-	
20	Taxable Capital Gain	-	-	-	
21					
22	TOTAL	$ (536)	$ (677)	$ (141)	- Sect 7-TAB 7.3, Schedule 31

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 2	$ 2	$ -	
3	Depreciation	500	518	18	- Sect 7-TAB 7.3, Schedule 29
4	Amortization of Decommissioning of Propane Assets	232	232	-	
5	Amortization of 75% Capital Contribution Costs	217	217	-	
6	Amortization of 75% Direct Appliance Conversion Costs	331	331	-	
7	Unpaid Remuneration	-	-	-	
8					
9	**Deductions:**				
10	Amortization of Deferred Charges	562	1,143	581	- Sect 7-TAB 7.3, Schedule 29
11	Less: Amortization of Decommissioning of Propane Assets (TGW)	(232)	(232)	-	
12	Less: Amortization of 75% Capital Contribution Costs (FEW)	(217)	(217)	-	
13	Less: Amortization of 75% Direct Appliance Conversion Costs (FEW)	(331)	(331)	-	
14	Capital Cost Allowance	(722)	(743)	(21)	- Sect 7-TAB 7.3, Schedule 38
15	Cumulative Eligible Capital Allowance	(931)	(866)	65	
16	Debt Issue Costs	-	-	-	
17	Overheads Capitalized Expensed for Tax Purposes	(82)	(82)	-	
18	Removal Costs	(6)	(6)	-	
19	Major Inspection Costs	-	-	-	
20	Taxable Capital Gain	-	-	-	
21					
22	TOTAL	$ (677)	$ (34)	$ 643	- Sect 7-TAB 7.3, Schedule 32

CAPITAL COST ALLOWANCE & CUMULATIVE ELIGIBLE CAPITAL CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 8,858	$ -	$ -	$ (354)	$ 8,504
2	1(b)	6%	15	-	28	(2)	41
3	2	6%	283	-	-	(17)	266
4	3	5%	-	-	-	-	-
5	6	10%	-	-	-	-	-
6	7	15%	-	-	-	-	-
7	8	20%	44	-	-	(9)	35
8	10	30%	60	-	17	(21)	56
9	12	100%	-	-	-	-	-
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	-	-	-	-	-
18	50 / 52	55% / 100%	-	-	-	-	-
19	51	6%	3,459	-	445	(221)	3,683
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 12,719	$ -	$ 490	$ (624)	$ 12,585
23							
24	Cross Reference					- Sect 7-TAB 7.3, Schedule 33	
25							
26							
27							

Line No.	* CUMULATIVE ELIGIBLE CAPITAL *					
29		2010	2011	2012	2013	
30	Particulars	ACTUAL	PROJECTED	FORECAST	FORECAST	Cross Reference
31	(1)	(2)	(3)	(4)	(5)	(6)
32						
33	CEC Opening Balance	$ 17,559	$ 18,767	$ 19,909	$ 20,840	
34						
35	75% of Eligible Capital Expenditures incurred	(20)	-		-	
36						
37	Subtotal:	17,539.0	18,767.0	19,909.0	20,840.0	
38						
39	Sale of Eligible Capital Property					
40	Sale of Eligible Capital Property before June 18, 1987					
41	Subtotal:	-	-	-	-	
42						
43	75 % Adjustment	-	-	-	-	
44						
45	Cumulative Eligible Capital Balance	17,539	18,767	19,909	20,840	
46						
47	Annual Allowance (7%)	(1,228)	(1,142)	(931)	(866)	- Sect 7-TAB 7.3, Schedule 33
48						
49	CEC Closing Balance	$ 18,767	$ 19,909	$ 20,840	$ 21,706	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	12/31/2011 UCC Balance	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 8,504	$ -	$ -	$ (340)	$ 8,164
2	1(b)	6%	41	-	239	(10)	270
3	2	6%	266	-	-	(16)	250
4	3	5%	-	-	-	-	-
5	6	10%	-	-	-	-	-
6	7	15%	-	-	-	-	-
7	8	20%	35	-	24	(10)	49
8	10	30%	56	1	20	(20)	57
9	12	100%	-	-	160	(80)	80
10	13	manual	-	-	85	(9)	76
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	-	-	-	-	-
18	50	55%	-	-	11	(3)	8
19	51	6%	3,683	-	437	(234)	3,886
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 12,585	$ 1	$ 976	$ (722)	$ 12,840
23							
24	Cross Reference					- Sect 7-TAB 7.3, Schedule 34	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 8,164	$ -	$ -	$ (327)	$ 7,837
2	1(b)	6%	270	-	11	(17)	264
3	2	6%	250	-	-	(15)	235
4	3	5%	-	-	-	-	-
5	6	10%	-	-	-	-	-
6	7	15%	-	-	-	-	-
7	8	20%	49	1	3	(10)	43
8	10	30%	57	-	60	(26)	91
9	12	100%	80	-	-	(80)	-
10	13	manual	76	1	-	(17)	60
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	-	-	-	-	-
18	50	55%	8	-	-	(4)	4
19	51	6%	3,886	-	453	(247)	4,092
20	43.2	0%	-	-	-	-	-
21							
22		Total	$ 12,840	$ 2	$ 527	$ (743)	$ 12,626
23							
24	Cross Reference					- Sect 7-TAB 7.3, Schedule 35	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	Gas Plant in Service, Beginning	$ 16,159	$ 16,056	$ 16,593	$ -	$ 16,593	$ 537	- Sect 7-TAB 7.3, Schedule 45
2	Opening Balance Adjustment	-	-	-	-	-	-	
3	Gas Plant in Service, Ending	16,594	16,394	16,216	-	16,216	(178)	- Sect 7-TAB 7.3, Schedule 45
4								
5	Accumulated Depreciation Beginning - Plant	$ 1,402	$ (3,323)	$ (3,167)	$ -	$ (3,167)	$ 156	- Sect 7-TAB 7.3, Schedule 54
6	Opening Balance Adjustment	-	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(3,168)	(3,669)	(2,588)	-	(2,588)	1,081	- Sect 7-TAB 7.3, Schedule 54
8								
9	Negative Salvage - Beginning	$ -	$ -	$ -	$ -	$ -	$ -	
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	Negative Salvage - Ending	-	-	-	-	-	-	
12								
13	CIAC, Beginning	$ (169)	$ (96)	$ (186)	$ -	$ (186)	$ (90)	- Sect 7-TAB 7.3, Schedule 63
14	Opening Balance Adjustment	-	-	-	-	-	-	
15	CIAC, Ending	(186)	(96)	(186)	-	(186)	(90)	- Sect 7-TAB 7.3, Schedule 63
16								
17	Accumulated Amortization Beginning - CIAC	$ 7	$ 9	$ 12	$ -	$ 12	$ 3	- Sect 7-TAB 7.3, Schedule 63
18	Opening Balance Adjustment	-	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	12	10	17	-	17	7	- Sect 7-TAB 7.3, Schedule 63
20								
21	Net Plant in Service, Mid-Year	$ 15,325	$ 12,643	$ 13,356	$ -	$ 13,356	$ 713	
22								
23	Adjustment to 13-Month Average	-	-	-	-	-	-	
24	Work in Progress, No AFUDC	18	63	23	-	23	(40)	
25	Unamortized Deferred Charges	29,440	29,176	30,864	-	30,864	1,688	- Sect 7-TAB 7.3, Schedule 67
26	Cash Working Capital	7	31	52	-	52	21	- Sect 7-TAB 7.3, Schedule 72
27	Other Working Capital	610	681	596	-	596	(85)	- Sect 7-TAB 7.3, Schedule 72
28	Future Income Taxes Regulatory Asset	1,800	-	2,009	-	2,009	2,009	- Sect 7-TAB 7.3, Schedule 78
29	Future Income Taxes Regulatory Liability	(1,800)	-	(2,009)	-	(2,009)	(2,009)	- Sect 7-TAB 7.3, Schedule 78
30	**Utility Rate Base**	$ 45,400	$ 42,594	$ 44,891	$ -	$ 44,891	$ 2,297	- Sect 7-TAB 7.3, Schedule 79
31								
32								
33								

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Adjustments	2012 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 16,593	$ 16,216	$ -	$ 16,216	$ (377)	- Sect 7-TAB 7.3, Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	16,216	17,203	-	17,203	987	- Sect 7-TAB 7.3, Schedule 48
4							
5	Accumulated Depreciation Beginning - Plant	$ (3,167)	$ (2,588)	$ -	$ (2,588)	$ 579	- Sect 7-TAB 7.3, Schedule 57
6	Opening Balance Adjustment (re Negative Salvage)	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 57
7	Accumulated Depreciation Ending - Plant	(2,588)	(2,933)	-	(2,933)	(345)	- Sect 7-TAB 7.3, Schedule 57
8							
9	Negative Salvage - Beginning	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.3, Schedule 61
10	Opening Balance Adjustment (re Negative Salvage)	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 61
11	Negative Salvage - Ending	-	(74)	-	(74)	(74)	- Sect 7-TAB 7.3, Schedule 61
12							
13	CIAC, Beginning	$ (186)	$ (186)	$ -	$ (186)	$ -	- Sect 7-TAB 7.3, Schedule 64
14	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 64
15	CIAC, Ending	(186)	(186)	-	(186)	-	- Sect 7-TAB 7.3, Schedule 64
16							
17	Accumulated Amortization Beginning - CIAC	$ 12	$ 17	$ -	$ 17	$ 5	- Sect 7-TAB 7.3, Schedule 64
18	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.3, Schedule 64
19	Accumulated Amortization Ending - CIAC	17	22	-	22	5	- Sect 7-TAB 7.3, Schedule 64
20							
21	Net Plant in Service, Mid-Year	$ 13,356	$ 13,746	$ -	$ 13,746	$ 390	
22							
23	* Adjustment to 13-Month Average	-	111	-	111	111	
24	Work in Progress, No AFUDC	23	23	-	23	-	
25	Unamortized Deferred Charges	30,864	27,584	-	27,584	(3,280)	- Sect 7-TAB 7.3, Schedule 69
26	Cash Working Capital	52	39	3	42	(10)	- Sect 7-TAB 7.3, Schedule 73
27	Other Working Capital	596	633	-	633	37	- Sect 7-TAB 7.3, Schedule 73
28	Future Income Taxes Regulatory Asset	2,009	2,172	-	2,172	163	- Sect 7-TAB 7.3, Schedule 78
29	Future Income Taxes Regulatory Liability	(2,009)	(2,172)	-	(2,172)	(163)	- Sect 7-TAB 7.3, Schedule 78
30	**Utility Rate Base**	$ 44,891	$ 42,136	$ 3	$ 42,139	$ (2,752)	- Sect 7-TAB 7.3, Schedule 80
31							
32	* January 1, 2011 In-Service date applied to Customer Care Enhancement						
33							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Adjustments	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 16,216	$ 17,203	$ -	$ 17,203	$ 987	- Sect 7-TAB 7.3, Schedule 51
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	17,203	17,637	-	17,637	434	- Sect 7-TAB 7.3, Schedule 51
4							
5	Accumulated Depreciation Beginning - Plant	$ (2,588)	$ (2,933)	$ -	$ (2,933)	$ (345)	- Sect 7-TAB 7.3, Schedule 60
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(2,933)	(3,200)	-	(3,200)	(267)	- Sect 7-TAB 7.3, Schedule 60
8							
9	Negative Salvage - Beginning	$ -	$ (74)	$ -	$ (74)	$ (74)	- Sect 7-TAB 7.3, Schedule 62
10	Opening Balance Adjustment	-	-	-	-	-	
11	Negative Salvage - Ending	(74)	(150)	-	(150)	(76)	- Sect 7-TAB 7.3, Schedule 62
12							
13	CIAC, Beginning	$ (186)	$ (186)	$ -	$ (186)	$ -	- Sect 7-TAB 7.3, Schedule 65
14	Opening Balance Adjustment	-	-	-	-	-	
15	CIAC, Ending	(186)	(186)	-	(186)	-	- Sect 7-TAB 7.3, Schedule 65
16							
17	Accumulated Amortization Beginning - CIAC	$ 17	$ 22	$ -	$ 22	$ 5	- Sect 7-TAB 7.3, Schedule 65
18	Opening Balance Adjustment	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	22	27	-	27	5	- Sect 7-TAB 7.3, Schedule 65
20							
21	Net Plant in Service, Mid-Year	$ 13,746	$ 14,080	$ -	$ 14,080	$ 334	
22							
23	Adjustment to 13-Month Average	111	-	-	-	(111)	
24	Work in Progress, No AFUDC	23	23	-	23	-	
25	Unamortized Deferred Charges	27,584	26,703	-	26,703	(881)	- Sect 7-TAB 7.3, Schedule 71
26	Cash Working Capital	42	44	17	61	19	- Sect 7-TAB 7.3, Schedule 74
27	Other Working Capital	633	635	-	635	2	- Sect 7-TAB 7.3, Schedule 74
28	Future Income Taxes Regulatory Asset	2,172	2,319	-	2,319	147	- Sect 7-TAB 7.3, Schedule 78
29	Future Income Taxes Regulatory Liability	(2,172)	(2,319)	-	(2,319)	(147)	- Sect 7-TAB 7.3, Schedule 78
30	**Utility Rate Base**	$ 42,139	$ 41,485	$ 17	$ 41,502	$ (637)	- Sect 7-TAB 7.3, Schedule 81
31							
32							
33							

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2011 Projected	2012 Forecast	2013 Forecast	Reference
	(1)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4					
5	Total Regular Capital Expenditures	$ 447	$ 719	$ 480	
6					
7	Special Projects - CPCN's				
8	CCE CPCN	90	44	-	
9	Total CPCN's	$ 90	$ 44	$ -	
10					
11					
12	TOTAL CAPITAL EXPENDITURES	$ 537	$ 762	$ 480	
13					
14					
15	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
16					
17	Regular Capital				
18	Regular Capital Expenditures	$ 447	$ 719	$ 480	
19	Add - Opening WIP	16	16	16	
20	Less - Closing WIP	(16)	(16)	(16)	
21	Add - AFUDC				
22	Add - Overhead Capitalized	121	127	128	- Sect 7-TAB 7.3, Schedule 45, 48, 5
23					
24	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 568	$ 846	$ 608	
25					
26	Special Projects - CPCN's				
27	CPCN Expenditures	90	44	-	
28	Add - Opening WIP	91	151	(26)	
29	Less - Closing WIP	(151)	26	26	
30	Adjustments	(36)			
31	Add - AFUDC	7			- Sect 7-TAB 7.3, Schedule 45, 48, 5
32					
33	TOTAL CPCN ADDITIONS	$ -	$ 221	$ -	
34					
35	TOTAL PLANT ADDITIONS	$ 568	$ 1,066	$ 608	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	8	-	-	-	-	-	-	8	8
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	87	-	-	-	-	-	-	87	87
13	402-01 Application Software - 12.5%	-	-	-	-	-	-	-	-	-
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	95	-	-	-	-	-	-	95	95
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	899	-	-	-	-	(899)	-	-	450
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	TOTAL MANUFACTURED	899	-	-	-	-	(899)	-	-	450

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**DISTRIBUTION PLANT**									
2	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
4	472-00 Structures & Improvements	2	-	-	-	-	-	-	2	2
5	473-00 Services	3,889	-	110	-	35	(1)	-	4,033	3,961
6	474-00 House Regulators & Meter Installations	1,402	-	23	-	7	-	-	1,432	1,417
7	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
8	475-00 Mains	8,723	-	249	-	79	(19)	-	9,032	8,878
9	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	477-00 Measuring & Regulating Equipment	640	-	-	-	-	-	-	640	640
11	477-00 Telemetering	2	-	-	-	-	-	-	2	2
12	478-10 Meters	462	-	23	-	-	(12)	-	473	468
13	478-20 Instruments	-	-	-	-	-	-	-	-	-
14	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
15	TOTAL DISTRIBUTION	15,120	-	405	-	121	(32)	-	15,614	15,367
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	17	-	-	-	-	-	-	17	17
6	- Masonry Buildings	-	-	25	-	-	-	-	25	13
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	9	-	-	-	-	-	-	9	9
10	483-40 GP Furniture	-	-	-	-	-	-	-	-	-
11	483-10 GP Computer Hardware	-	-	-	-	-	-	-	-	-
12	483-20 GP Computer Software	-	-	-	-	-	-	-	-	-
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	154	-	17	-	-	-	-	171	163
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	95	-	-	-	-	(3)	-	92	94
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	188	-	-	-	-	(11)	-	177	183
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	16	-	-	-	-	-	-	16	16
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	479	-	42	-	-	(14)	-	507	493
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 16,593	$ -	$ 447	$ -	$ 121	$ (945)	$ -	$ 16,216	$ 16,405
33										
34	Cross Reference	- Sect 7-TAB 7.3, Schedule 39							- Sect 7-TAB 7.3, Schedule 39	
35		- Sect 7-TAB 7.3, Schedule 42							- Sect 7-TAB 7.3, Schedule 54	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	8	-	-	-	-	-	-	8	8
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	87	-	-	-	-	-	-	87	87
13	402-01 Application Software - 12.5%	-	167	-	-	-	-	-	167	251
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	95	167	-	-	-	-	-	262	346
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	TOTAL MANUFACTURED	-	-	-	-	-	-	-	-	-

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**DISTRIBUTION PLANT**									
2	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
4	472-00 Structures & Improvements	2	-	-	-	-	-	-	2	2
5	473-00 Services	4,033	-	109	-	38	(1)	-	4,179	4,106
6	474-00 House Regulators & Meter Installations	1,432	-	-	-	-	-	-	1,432	1,432
7	477-00 Meters/Regulators Installations	-	-	23	-	-	-	-	23	12
8	475-00 Mains	9,032	-	254	-	89	(20)	-	9,355	9,194
9	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	477-00 Measuring & Regulating Equipment	640	-	-	-	-	-	-	640	640
11	477-00 Telemetering	2	-	-	-	-	-	-	2	2
12	478-10 Meters	473	-	23	-	-	(12)	-	484	479
13	478-20 Instruments	-	-	-	-	-	-	-	-	-
14	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
15	TOTAL DISTRIBUTION	15,614	-	409	-	127	(33)	-	16,117	15,866
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	17	-	-	-	-	-	-	17	17
6	- Masonry Buildings	25	24	200	-	-	-	-	249	137
7	- Leasehold Improvement	-	10	75	-	-	-	-	85	53
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	9	1	-	-	-	-	-	10	11
10	483-40 GP Furniture	-	8	15	-	-	-	-	23	20
11	483-10 GP Computer Hardware	-	11	-	-	-	-	-	11	16
12	483-20 GP Computer Software	-	-	-	-	-	-	-	-	-
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	171	-	20	-	-	(47)	-	144	158
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	92	-	-	-	-	-	-	92	92
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	177	-	-	-	-	-	-	177	177
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	16	-	-	-	-	-	-	16	16
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	507	54	310	-	-	(47)	-	824	696
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 16,216	$ 221	$ 719	$ -	$ 127	$ (80)	$ -	$ 17,203	$ 16,907
33										
34	Cross Reference	- Sect 7-TAB 7.3, Schedule 40							- Sect 7-TAB 7.3, Schedule 40	
35		- Sect 7-TAB 7.3, Schedule 42							- Sect 7-TAB 7.3, Schedule 57	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	8	-	-	-	-	-	-	8	8
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	87	-	-	-	-	-	-	87	87
13	402-01 Application Software - 12.5%	167	-	-	-	-	-	-	167	167
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	262	-	-	-	-	-	-	262	262
16										
17	**MANUFACTURED GAS / LOCAL STORAGE**									
18	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
19	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
26	TOTAL MANUFACTURED	-	-	-	-	-	-	-	-	-

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**DISTRIBUTION PLANT**									
2	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
4	472-00 Structures & Improvements	2	-	-	-	-	-	-	2	2
5	473-00 Services	4,179	-	103	-	37	(1)	-	4,318	4,249
6	474-00 House Regulators & Meter Installations	1,432	-	-	-	-	(124)	-	1,308	1,370
7	477-00 Meters/Regulators Installations	23	-	23	-	-	-	-	46	35
8	475-00 Mains	9,355	-	258	-	91	(20)	-	9,684	9,520
9	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	477-00 Measuring & Regulating Equipment	640	-	-	-	-	-	-	640	640
11	477-00 Telemetering	2	-	-	-	-	-	-	2	2
12	478-10 Meters	484	-	23	-	-	(12)	-	495	490
13	478-20 Instruments	-	-	-	-	-	-	-	-	-
14	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
15	TOTAL DISTRIBUTION	16,117	-	407	-	128	(157)	-	16,495	16,306
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued) -
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	17	-	-	-	-	-	-	17	17
6	- Masonry Buildings	249	-	10	-	-	-	-	259	254
7	- Leasehold Improvement	85	-	-	-	-	-	-	85	85
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	10	-	3	-	-	-	-	13	12
10	483-40 GP Furniture	23	-	-	-	-	-	-	23	23
11	483-10 GP Computer Hardware	11	-	-	-	-	-	-	11	11
12	483-20 GP Computer Software	-	-	-	-	-	-	-	-	-
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	144	-	60	-	-	-	-	204	174
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	92	-	-	-	-	-	-	92	92
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	177	-	-	-	-	(17)	-	160	169
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	16	-	-	-	-	-	-	16	16
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	824	-	73	-	-	(17)	-	880	852
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 17,203	$ -	$ 480	$ -	$ 128	$ (174)	$ -	$ 17,637	$ 17,420
33										
34	Cross Reference	- Sect 7-TAB 7.3, Schedule 41							- Sect 7-TAB 7.3, Schedule 41	
35		- Sect 7-TAB 7.3, Schedule 42							- Sect 7-TAB 7.3, Schedule 60	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	8	4.11%	-	-	-	2	2
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	0.00%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	87	1.40%	1	-	-	10	11
13	402-01 Application Software - 12.5%	-	12.50%	-	-	-	-	-
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	95		1	-	-	12	13
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	450	0.00%	-	-	(899)	-	(899)
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	2.50%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	14.35%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	2.74%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	5.18%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	13.16%	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Ha	-	0.00%	-	-	-	-	-
26	TOTAL MANUFACTURED	450		-	-	(899)	-	(899)

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1								
2	**DISTRIBUTION PLANT**							
3	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
4	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
5	472-00 Structures & Improvements	2	3.26%	-	-	-	-	-
6	473-00 Services	3,961	1.94%	77	-	(1)	667	743
7	474-00 House Regulators & Meter Installations	1,417	3.33%	47	-	-	338	385
8	477-00 Meters/Regulators Installations	-	0.00%	-	-	-	-	-
9	475-00 Mains	8,878	1.66%	147	-	(19)	1,749	1,877
10	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
11	477-00 Measuring & Regulating Equipment	640	4.60%	29	-	-	32	61
12	477-00 Telemetering	2	4.60%	-	-	-	-	-
13	478-10 Meters	468	4.66%	22	-	(12)	107	117
14	478-20 Instruments	-	0.00%	-	-	-	-	-
15	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
16	TOTAL DISTRIBUTION	15,367		322	-	(32)	2,893	3,183
17								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust- ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	17	4.41%	1	-	-	2	3
6	- Masonry Buildings	13	4.41%	1	-	-	-	1
7	- Leasehold Improvement	-	0.00%	-	-	-	-	-
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	9	6.67%	1	-	-	6	7
10	483-40 GP Furniture	-	5.00%	-	-	-	-	-
11	483-10 GP Computer Hardware	-	20.00%	-	-	-	-	-
12	483-20 GP Computer Software	-	20.00%	-	-	-	-	-
13	483-21 GP Computer Software	-	0.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	163	16.01%	26	-	-	61	87
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	94	4.63%	4	-	(3)	68	69
18	485-20 Heavy Mobile Equipment	-	6.67%	-	-	-	-	-
19	486-00 Small Tools & Equipment	183	5.00%	9	-	(11)	113	111
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	16	6.67%	1	-	-	12	13
24	- Radio	-	6.67%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	493		43	-	(14)	262	291
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 16,405		$ 366	$ -	$ (945)	$ 3,167	$ 2,588
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			-				
35	**Net Depreciation Expense**			$ 366				
36								
37	Cross Reference	- Sect 7-TAB 7.3, Schedule 45		- Sect 7-TAB 7.3, Schedule 27			- Sect 7-TAB 7.3, Schedule 39	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	8	4.33%	-	-	-	2	2
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	0.00%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	87	0.00%	-	-	-	11	11
13	402-01 Application Software - 12.5%	251	12.50%	21	-	-	-	21
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	346		21	-	-	13	34
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	(899)	(899)
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	2.50%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	14.35%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	2.74%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	5.18%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	13.16%	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Ha	-	0.00%	-	-	-	-	-
26	TOTAL MANUFACTURED	-		-	-	-	(899)	(899)

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1								
2	**DISTRIBUTION PLANT**							
3	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
4	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
5	472-00 Structures & Improvements	2	3.37%	-	-	-	-	-
6	473-00 Services	4,106	2.06%	85	-	(1)	743	827
7	474-00 House Regulators & Meter Installations	1,432	5.13%	73	-	-	385	458
8	477-00 Meters/Regulators Installations	12	4.55%	1	-	-	-	1
9	475-00 Mains	9,194	1.51%	139	-	(20)	1,877	1,996
10	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
11	477-00 Measuring & Regulating Equipment	640	3.86%	25	-	-	61	86
12	477-00 Telemetering	2	3.72%	-	-	-	-	-
13	478-10 Meters	479	6.46%	31	-	(12)	117	136
14	478-20 Instruments	-	0.00%	-	-	-	-	-
15	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
16	TOTAL DISTRIBUTION	15,866		354	-	(33)	3,183	3,504
17								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	17	4.60%	1	-	-	3	4
6	- Masonry Buildings	137	4.41%	6	-	-	1	7
7	- Leasehold Improvement	53	10.00%	5	-	-	-	5
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	11	6.67%	1	-	-	7	8
10	483-40 GP Furniture	20	5.00%	1	-	-	-	1
11	483-10 GP Computer Hardware	16	20.00%	2	-	-	-	2
12	483-20 GP Computer Software	-	20.00%	-	-	-	-	-
13	483-21 GP Computer Software	-	0.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	158	13.15%	21	-	(47)	87	61
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	92	3.18%	3	-	-	69	72
18	485-20 Heavy Mobile Equipment	-	6.67%	-	-	-	-	-
19	486-00 Small Tools & Equipment	177	5.00%	9	-	-	111	120
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	16	6.67%	1	-	-	13	14
24	- Radio	-	0.00%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	696		50	-	(47)	291	294
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 16,907		$ 425	$ -	$ (80)	$ 2,588	$ 2,933
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			-				
35	**Net Depreciation Expense**			$ 425				
36								
37	Cross Reference	- Sect 7-TAB 7.3, Schedule 48		- Sect 7-TAB 7.3, Schedule 28			- Sect 7-TAB 7.3, Schedule 40	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	0.00%	-	-	-	-	-
4	178-00 Organization Expense	-	0.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	8	4.33%	-	-	-	2	2
7	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	0.00%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	87	0.00%	-	-	-	11	11
13	402-01 Application Software - 12.5%	167	12.50%	21	-	-	21	42
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	262		21	-	-	34	55
16								
17	**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	(899)	(899)
19	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
20	432-00 Manufact'd Gas - Struct. & Improvements	-	2.50%	-	-	-	-	-
21	433-00 Manufact'd Gas - Equipment	-	14.35%	-	-	-	-	-
22	434-00 Manufact'd Gas - Gas Holders	-	2.74%	-	-	-	-	-
23	436-00 Manufact'd Gas - Compressor Equipment	-	5.18%	-	-	-	-	-
24	437-00 Manufact'd Gas - Measuring & Regulating Equi	-	13.16%	-	-	-	-	-
25	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Ha	-	0.00%	-	-	-	-	-
26	TOTAL MANUFACTURED	-		-	-	-	(899)	(899)

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1								
2	**DISTRIBUTION PLANT**							
3	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
4	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
5	472-00 Structures & Improvements	2	3.37%	-	-	-	-	-
6	473-00 Services	4,249	2.06%	87	-	(1)	827	913
7	474-00 House Regulators & Meter Installations	1,370	5.13%	70	-	(124)	458	404
8	477-00 Meters/Regulators Installations	35	4.55%	2	-	-	1	3
9	475-00 Mains	9,520	1.51%	144	-	(20)	1,996	2,120
10	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-
11	477-00 Measuring & Regulating Equipment	640	3.86%	25	-	-	86	111
12	477-00 Telemetering	2	3.72%	-	-	-	-	-
13	478-10 Meters	490	6.46%	32	-	(12)	136	156
14	478-20 Instruments	-	0.00%	-	-	-	-	-
15	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
16	TOTAL DISTRIBUTION	16,306		360	-	(157)	3,504	3,707
17								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	17	4.60%	1	-	-	4	5
6	- Masonry Buildings	254	4.41%	11	-	-	7	18
7	- Leasehold Improvement	85	10.00%	9	-	-	5	14
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	12	6.67%	1	-	-	8	9
10	483-40 GP Furniture	23	5.00%	1	-	-	1	2
11	483-10 GP Computer Hardware	11	20.00%	2	-	-	2	4
12	483-20 GP Computer Software	-	20.00%	-	-	-	-	-
13	483-21 GP Computer Software	-	0.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	174	13.15%	23	-	-	61	84
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	92	3.18%	3	-	-	72	75
18	485-20 Heavy Mobile Equipment	-	6.67%	-	-	-	-	-
19	486-00 Small Tools & Equipment	169	5.00%	8	-	(17)	120	111
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	16	6.67%	1	-	-	14	15
24	- Radio	-	0.00%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	852		60	-	(17)	294	337
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 17,420		$ 441	$ -	$ (174)	$ 2,933	$ 3,200
33								
34	Less: Vehicle Depreciation Allocated To Capital Projects			-				
35	**Net Depreciation Expense**			$ 441				
36								
37	Cross Reference	- Sect 7-TAB 7.3, Schedule 51		- Sect 7-TAB 7.3, Schedule 29			- Sect 7-TAB 7.3, Schedule 41	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	472-00 Structures & Improvements	2	0.17%	-	-	-	-	-	-
3	473-00 Services	4,106	1.00%	41	-	(5)	-	-	36
4	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
5	474-00 House Regulators & Meter Installations	1,432	0.65%	9	-	-	-	-	9
6	475-00 Mains	9,194	0.30%	28	-	(1)	-	-	27
7	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
8	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	640	0.00%	-	-	-	-	-	-
10	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
11	478-10 Meters	479	0.41%	2	-	-	-	-	2
12	TOTAL DISTRIBUTION	15,866		80	-	(6)	-	-	74
13									
14									
15	TOTALS	$ 16,907		$ 80	$ -	$ (6)	$ -	$ -	$ 74
16									
17	Cross Reference	- Sect 7-TAB 7.3, Schedule 48		- Sect 7-TAB 7.3, Schedule 28				- Sect 7-TAB 7.3, Schedule 40	
18									

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	472-00 Structures & Improvements	2	0.17%	-	-	-	-	-	-
3	473-00 Services	4,249	1.00%	42	-	(5)	-	36	73
4	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
5	474-00 House Regulators & Meter Installations	1,370	0.65%	9	-	-	-	9	18
6	475-00 Mains	9,520	0.30%	29	-	(1)	-	27	55
7	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
8	476-00 Compressor Equipment	-	0.00%	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	640	0.00%	-	-	-	-	-	-
10	477-10 Measuring & Regulating Equipment - Byron Cr	-	0.00%	-	-	-	-	-	-
11	478-10 Meters	490	0.41%	2	-	-	-	2	4
12	TOTAL DISTRIBUTION	16,306		82	-	(6)	-	74	150
13									
14									
15	TOTALS	$ 17,420		$ 82	$ -	$ (6)	$ -	$ 74	$ 150
16									
17	Cross Reference	- Sect 7-TAB 7.3, Schedule 51		- Sect 7-TAB 7.3, Schedule 29				- Sect 7-TAB 7.3, Schedule 41	
18									

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 186	$ -	$ -	$ -	$ 186	
4							
5	TOTAL Contributions	186	-	-	-	186	- Sect 7-TAB 7.3, Schedule 39
6							
7							
8							
9	**Amortization**						
10							
11	Distribution Contributions	(12)	-	(5)	-	(17)	
12							
13	TOTAL CIAC Amortization	(12)	-	(5)	-	(17)	- Sect 7-TAB 7.3, Schedule 39
14							
15	**NET CONTRIBUTIONS**	$ 174	$ -	$ (5)	$ -	$ 169	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 Additions	2012 Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 186	$ -	$ -	$ -	$ 186	
4							
5	TOTAL Contributions	186	-	-	-	186	- Sect 7-TAB 7.3, Schedule 40
6							
7							
8							
9	**Amortization**						
10							
11	Distribution Contributions	(17)	-	(5)	-	(22)	
12							
13	TOTAL CIAC Amortization	(17)	-	(5)	-	(22)	- Sect 7-TAB 7.3, Schedule 40
14							
15	**NET CONTRIBUTIONS**	$ 169	$ -	$ (5)	$ -	$ 164	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 Additions	2013 Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 186	$ -	$ -	$ -	$ 186	
4							
5	TOTAL Contributions	186	-	-	-	186	- Sect 7-TAB 7.3, Schedule 41
6							
7							
8							
9	**Amortization**						
10							
11	Distribution Contributions	(22)	-	(5)	-	(27)	
12							
13	TOTAL CIAC Amortization	(22)	-	(5)	-	(27)	- Sect 7-TAB 7.3, Schedule 41
14							
15	**NET CONTRIBUTIONS**	$ 164	$ -	$ (5)	$ -	$ 159	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries: Rider	Recoveries: Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (58)	$ -	$ (160)	$ 42	$ (118)	$ -	$ -	$ -	$ (176)	$ (117)
3	Midstream Cost Reconciliation Account (MCRA)	39	-	108	(29)	79	-	-	-	119	79
4	Revenue Stabilization Adjustment Mechanism (RSAM)	151	-	311	(82)	228	-	-	-	379	265
5	Interest on CCRA / MCRA / RSAM / Gas Storage	-	-	(29)	8	(21)	-	-	-	(21)	(10)
6	Gas Cost Reconciliation Account (GCRA)	11,492	-	-	-	-	-	-	-	11,492	11,492
7	Cost of Gas - Rate Rider A	(12,015)	-	711	(189)	523	-	-	-	(11,492)	(11,754)
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	-	-	-	-	-	-	-	-	-	-
11	Carbon Strategy	-	-	-	-	-	-	-	-	-	-
12											
13	Non-Controllable Items										
14	Property Tax Deferral	51	-	56	(15)	41	-	-	-	92	72
15	Insurance Variance	-	-	-	-	-	-	-	-	-	-
16	Interest Variance	(311)	-	(26)	7	(19)	-	-	-	(329)	(320)
17	Tax Variance Account	(2)	-	-	-	-	-	-	-	(2)	(2)
18	Olympics Security Costs Deferral	13	-	-	-	-	(9)	-	-	4	9
19	IFRS Conversion Costs	8	-	-	-	-	(2)	-	-	6	7
20	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
21											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 6	$ -	$ -	$ -	$ -	$ (1)	$ -	$ -	$ 5	$ 5
3	2010-2011 Revenue Requirement Application	298	-	1	(0)	1	(35)	-	-	263	281
4	2012-2013 Revenue Requirement Application	-	-	13	(3)	9	-	-	-	9	5
5	CCE CPCN Application	3	-	-	-	-	(0)	-	-	2	2
6	Long Term Resource Plan Application	-	-	2	(0)	1	-	-	-	1	1
7											
8	Whistler Pipeline										
9	Whistler Pipeline Conversion	14,535	-	(533)	-	(533)	(714)	-	-	13,288	13,911
10	Capital Contribution to TGVI	16,693	-	-	-	-	(341)	-	-	16,353	16,523
11	Pipeline Contribution Costs Variance Account	-	-	-	-	-	-	-	-	-	-
12											
13	Other										
14	Deferred Removal Costs	3	-	-	-	-	-	-	-	3	3
15	Gains and Losses on Asset Disposition	132	-	-	-	-	-	-	-	132	132
16	2010-2011 Customer Service O&M and COS	-	-	-	-	-	-	-	-	-	-
17	Gas Asset Records Project	-	-	-	-	-	-	-	-	-	-
18	BC OneCall Project	-	-	-	-	-	-	-	-	-	-
19	IFRS Transitional Costs	(58)	-	-	-	-	-	-	-	(58)	(58)
20											
21	Residual Deferred Charges										
22	Deferred ROE Variance	(210)	-	-	-	-	163	-	-	(47)	(128)
23	Sales Margin Differential	464	-	-	-	-	-	-	-	464	464
24	FEW 2009 Revenue Requirement Application	1	-	-	-	-	-	-	-	1	1
25											
26	Total Deferred Charges for Rate Base	$ 31,237	$ -	$ 455	$ (261)	$ 193	$ (940)	$ -	$ -	$ 30,491	$ 30,864
27											
28	Cross Reference						- Sect 7-TAB 7.3, Schedule 27			- Sect 7-TAB 7.3, Schedule 39	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (176)	$ -	$ 234	$ (59)	$ 176	$ -	$ -	$ -	$ (0)	$ (88)
3	Midstream Cost Reconciliation Account (MCRA)	119	-	-	-	-	-	(53)	13	79	99
4	Revenue Stabilization Adjustment Mechanism (RSAM)	379	464	-	-	-	-	(375)	94	562	703
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(21)	-	26	(6)	20	-	-	-	(1)	(11)
6	Gas Cost Reconciliation Account (GCRA)	11,492	(11,492)	-	-	-	-	-	-	-	-
7	Cost of Gas - Rate Rider A	(11,492)	11,492	-	-	-	-	-	-	(0)	-
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	-	-	200	(50)	150	-	-	-	150	75
11	Carbon Strategy	-	-	-	-	-	-	-	-	-	-
12											
13	Non-Controllable Items										
14	Property Tax Deferral	92	-	-	-	-	(25)	-	-	67	80
15	Insurance Variance	-	-	-	-	-	-	-	-	-	-
16	Interest Variance	(329)	-	-	-	-	329	-	-	(0)	(165)
17	Tax Variance Account	(2)	-	-	-	-	2	-	-	-	(1)
18	Olympics Security Costs Deferral	4	-	-	-	-	(4)	-	-	(0)	2
19	IFRS Conversion Costs	6	-	-	-	-	(3)	-	-	3	5
20	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
21											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 5	$ -	$ -	$ -	$ -	$ (1)	$ -	$ -	$ 4	$ 4
3	2010-2011 Revenue Requirement Application	263	-	-	-	-	(263)	-	-	-	132
4	2012-2013 Revenue Requirement Application	9	-	-	-	-	(5)	-	-	5	7
5	CCE CPCN Application	2	-	-	-	-	(1)	-	-	2	2
6	Long Term Resource Plan Application	1	-	1	(0)	1	-	-	-	2	2
7											
8	Whistler Pipeline										
9	Whistler Pipeline Conversion	13,288	-	-	-	-	(740)	-	-	12,548	12,918
10	Capital Contribution to TGVI	16,353	(2,484)	-	-	-	(289)	-	-	13,580	13,724
11	Pipeline Contribution Costs Variance Account	-	(434)	-	-	-	434	-	-	-	(217)
12											
13	Other										
14	Deferred Removal Costs	3	-	-	-	-	(2)	-	-	2	3
15	Gains and Losses on Asset Disposition	132	(58)	-	-	-	(4)	-	-	71	72
16	2010-2011 Customer Service O&M and COS	-	248	50	(12)	37	(31)	-	-	254	251
17	Gas Asset Records Project	-	-	20	(5)	15	(3)	-	-	12	6
18	BC OneCall Project	-	-	13	(3)	9	(2)	-	-	8	4
19	IFRS Transitional Costs	(58)	58	-	-	-	-	-	-	-	-
20											
21	Residual Deferred Charges										
22	Deferred ROE Variance	(47)	-	-	-	-	47	-	-	0	(24)
23	Sales Margin Differential	464	(464)	-	-	-	-	-	-	-	-
24	FEW 2009 Revenue Requirement Application	1	-	-	-	-	(1)	-	-	-	1
25											
26	Total Deferred Charges for Rate Base	$ 30,491	$ (2,670)	$ 543	$ (135)	$ 408	$ (562)	$ (428)	$ 107	$ 27,346	$ 27,584
27											
28	Cross Reference						- Sect 7-TAB 7.3, Schedule 28			- Sect 7-TAB 7.3, Schedule 40	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)
3	Midstream Cost Reconciliation Account (MCRA)	79	-	-	-	-	-	(53)	13	40	59
4	Revenue Stabilization Adjustment Mechanism (RSAM)	562	-	-	-	-	-	(375)	94	281	422
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(1)	-	(0)	-	(0)	-	-	-	(1)	(1)
6	Gas Cost Reconciliation Account (GCRA)	-	-	-	-	-	-	-	-	-	-
7	Cost of Gas - Rate Rider A	(0)	-	-	-	-	-	-	-	(0)	-
8											
9	Energy Policy Related										
10	Energy Efficiency & Conservation (EEC)	150	-	200	(50)	150	(15)	-	-	285	218
11	Carbon Strategy	-	-	-	-	-	-	-	-	-	-
12											
13	Non-Controllable Items										
14	Property Tax Deferral	67	-	-	-	-	(34)	-	-	34	50
15	Insurance Variance	-	-	-	-	-	-	-	-	-	-
16	Interest Variance	(0)	-	-	-	-	-	-	-	(0)	(0)
17	Tax Variance Account	-	-	-	-	-	-	-	-	-	-
18	Olympics Security Costs Deferral	(0)	-	-	-	-	(4)	-	-	(5)	(2)
19	IFRS Conversion Costs	3	-	-	-	-	(3)	-	-	0	2
20	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
21											

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 4	$ -	$ -	$ -	$ -	$ (1)	$ -	$ -	$ 2	$ 3
3	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
4	2012-2013 Revenue Requirement Application	5	-	-	-	-	(5)	-	-	-	2
5	CCE CPCN Application	2	-	-	-	-	(1)	-	-	1	1
6	Long Term Resource Plan Application	2	-	2	(1)	2	-	-	-	3	3
7											
8	Whistler Pipeline										
9	Whistler Pipeline Conversion	12,548	-	-	-	-	(740)	-	-	11,808	12,178
10	Capital Contribution to TGVI	13,580	-	-	-	-	(289)	-	-	13,291	13,435
11	Pipeline Contribution Costs Variance Account	-	-	-	-	-	-	-	-	-	-
12											
13	Other										
14	Deferred Removal Costs	2	-	-	-	-	(2)	-	-	-	1
15	Gains and Losses on Asset Disposition	71	-	-	-	-	(4)	-	-	67	69
16	2010-2011 Customer Service O&M and COS	254	-	-	-	-	(36)	-	-	219	237
17	Gas Asset Records Project	12	-	23	(6)	17	(6)	-	-	23	17
18	BC OneCall Project	8	-	13	(3)	9	(4)	-	-	13	10
19	IFRS Transitional Costs	-	-	-	-	-	-	-	-	-	-
20											
21	Residual Deferred Charges										
22	Deferred ROE Variance	0	-	-	-	-	-	-	-	0	-
23	Sales Margin Differential	-	-	-	-	-	-	-	-	-	-
24	FEW 2009 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
25											
26	Total Deferred Charges for Rate Base	$ 27,346	$ -	$ 237	$ (59)	$ 178	$ (1,143)	$ (428)	$ 107	$ 26,060	$ 26,703
27											
28	Cross Reference						- Sect 7-TAB 7.3, Schedule 29			- Sect 7-TAB 7.3, Schedule 41	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 61	$ 55	$ 56	$ 56	$ 1	- Sect 7-TAB 7.3, Schedule 75
4							
5							
6	Less - Funds Available:						
7							
8	Withholdings From Employees	(54)	(24)	(4)	(4)	20	
9							
10	Subtotal	7	31	52	52	21	- Sect 7-TAB 7.3, Schedule 39
11							
12	**Other Working Capital Items**						
13	Construction Advances	-	(4)	(13)	(13)	(9)	
14	Transmission Line Pack Gas	7	30	17	17	(13)	
15	Gas in Storage	616	655	592	592	(63)	
16							
17	Subtotal	610	681	596	596	(85)	- Sect 7-TAB 7.3, Schedule 39
18							
19	Total	$ 617	$ 712	$ 648	$ 648	$ (64)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 56	$ 43	$ 46	$ (10)	- Sect 7-TAB 7.3, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Withholdings From Employees	(4)	(4)	(4)	-	
9						
10	Subtotal	52	39	42	(10)	- Sect 7-TAB 7.3, Schedule 40
11						
12	**Other Working Capital Items**					
13	Construction Advances	(13)	(13)	(13)	-	
14	Transmission Line Pack Gas	17	18	18	1	
15	Gas in Storage	592	628	628	36	
16						
17	Subtotal	596	633	633	37	- Sect 7-TAB 7.3, Schedule 40
18						
19	Total	$ 648	$ 672	$ 675	$ 27	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 46	$ 46	$ 65	$ 19	- Sect 7-TAB 7.3, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Withholdings From Employees	(4)	(4)	(4)	-	
9						
10	Subtotal	42	42	61	19	- Sect 7-TAB 7.3, Schedule 41
11						
12	**Other Working Capital Items**					
13	Construction Advances	(13)	(13)	(13)	-	
14	Transmission Line Pack Gas	18	23	23	5	
15	Gas in Storage	628	625	625	(3)	
16						
17	Subtotal	633	635	635	2	- Sect 7-TAB 7.3, Schedule 41
18						
19	Total	$ 675	$ 677	$ 696	$ 21	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011			2012			2013			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	38.6			38.6			38.7			- Sect 7-TAB 7.3, Schedule 76
4	Expense Lead Days	36.3			36.8			36.8			- Sect 7-TAB 7.3, Schedule 77
5											- Sect 7-TAB 7.3, Schedule 72
6	Net Lead/(Lag) Days	2.3	$ 8,826	$ 56	1.8	$ 8,774	$ 43	1.9	$ 8,801	$ 46	- Sect 7-TAB 7.3, Schedule 73
7											- Sect 7-TAB 7.3, Schedule 74
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	38.6			38.6			38.7			- Sect 7-TAB 7.3, Schedule 76
13	Expense Lead Days	36.3			36.7			36.1			- Sect 7-TAB 7.3, Schedule 77
14											- Sect 7-TAB 7.3, Schedule 72
15	Net Lead/(Lag) Days	2.3	$ 8,825	$ 56	1.9	$ 8,824	$ 46	2.6	$ 9,109	$ 65	- Sect 7-TAB 7.3, Schedule 73
16											- Sect 7-TAB 7.3, Schedule 74
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 3			$ 19	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Revenue At 2011 Rates	2011 Lag Days Service to Collection	2011 Dollar Days	2012 Revenue At 2011 Rates	2012 Lag Days Service to Collection	2012 Dollar Days	2013 Revenue At 2011 Rates	2013 Lag Days Service to Collection	2013 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											
3	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.3, Schedule 14
4	Residential and Commercial	$ 6,821	38.7	$ 263,988	$ 7,145	38.7	$ 276,500	$ 7,495	38.7	$ 290,041	- Sect 7-TAB 7.3, Schedule 16
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	4,603	38.5	177,337	4,062	38.5	156,556	3,599	38.5	138,723	
6	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
7											
8	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	-	0.0	-	-	0.0	-	0	0.0	-	
9											
10	Total Gas Sales	11,424	38.6	441,325	11,207	38.6	433,056	11,093	38.7	428,764	
11	Other Revenues										
12	Royalty Revenue (FEVI)	-	45.6	-	-	45.6	-	-	45.6	-	- Sect 7-TAB 7.3, Schedule 4
13	Late Payment Charges	11	37.6	414	11	37.6	414	11	37.6	414	- Sect 7-TAB 7.3, Schedule 18
14	Returned Cheque Charges	-	0.0	11	-	0.0	11	-	0.0	11	- Sect 7-TAB 7.3, Schedule 19
15	Connection Charges	4	34.5	138	4	34.5	138	4	34.5	138	- Sect 7-TAB 7.3, Schedule 20
16	Other Utility Income	1	46.0	46	1	46.0	46	1	46.0	46	
17											
18											
19	Total Revenue	$ 11,440	38.6	$ 441,934	$ 11,223	38.6	$ 433,665	$ 11,109	38.7	$ 429,373	
20											
21											
22	**REVENUE, REVISED RATES**										
23											
24	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.3, Schedule 14
25	Residential and Commercial	$ 6,821	38.7	$ 263,988	$ 7,254	38.7	$ 280,717	$ 8,217	38.7	$ 317,983	- Sect 7-TAB 7.3, Schedule 16
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	4,603	38.5	177,337	4,125	38.5	158,984	3,956	38.5	152,485	
27	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
28											
29	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	-	0.0	-	-	0.0	-	0	0.0	-	
30											
31	Total Gas Sales	11,424	38.6	441,325	11,379	38.6	439,701	12,172	38.7	470,468	
32	Other Revenues										- Sect 7-TAB 7.3, Schedule 18
33	Royalty Revenue (FEVI)	-	45.6	-	-	45.6	-	-	45.6	-	- Sect 7-TAB 7.3, Schedule 19
34	Late Payment Charges	11	37.6	414	11	37.6	414	11	37.6	414	- Sect 7-TAB 7.3, Schedule 20
35	Returned Cheque Charges	-	0.0	11	-	0.0	11	-	0.0	11	
36	Connection Charges	4	34.5	138	4	34.5	138	4	34.5	138	
37	Other Utility Income	1	46.0	46	1	46.0	46	1	46.0	46	
38											
39											
40	Total Revenue	$ 11,440	38.6	$ 441,934	$ 11,395	38.6	$ 440,310	$ 12,188	38.7	$ 471,077	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

			2011			2012			2013			
Line No.	Particulars		Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**											
2												
3	Operating And Maintenance											- Sect 7-TAB 7.3, Schedule 4
4	Expenses		$ 747	35.8	$ 26,743	$ 779	35.8	$ 27,888	$ 787	35.8	$ 28,175	- Sect 7-TAB 7.3, Schedule 5
5	Transportation Costs		2,585	40.2	103,917	2,585	40.2	103,917	2,585	40.2	103,917	- Sect 7-TAB 7.3, Schedule 6
6	Gas Purchases (excl Royalty Credits)		3,562	40.2	143,192	3,493	40.2	140,419	3,455	40.2	138,891	
7												
8	Taxes Other Than Income											- Sect 7-TAB 7.3, Schedule 24
9	Property Taxes		334	2.6	868	236	2.6	614	244	2.6	634	- Sect 7-TAB 7.3, Schedule 25
10	Carbon Tax		816	29.5	24,079	978	29.5	28,845	1,056	29.5	31,138	
11	HST - Net	*	218	39.8	8,671	513	39.8	20,405	507	39.8	20,193	
12	PST Component of HST (REC)	*	205	37.1	7,617	(102)	34.8	(3,552)	(105)	34.8	(3,658)	- Sect 7-TAB 7.3, Schedule 30
13	Income Tax		358	15.2	5,442	293	15.2	4,454	273	15.2	4,150	- Sect 7-TAB 7.3, Schedule 31
14												- Sect 7-TAB 7.3, Schedule 32
15	Total		$ 8,825	36.3	$ 320,528	$ 8,774	36.8	$ 322,990	$ 8,802	36.7	$ 323,440	
16												
17												
18	**EXPENSES, REVISED RATES**											
19												
20	Operating And Maintenance											- Sect 7-TAB 7.3, Schedule 4
21	Expenses		$ 747	35.8	$ 26,743	$ 779	35.8	$ 27,888	$ 787	35.8	$ 28,175	- Sect 7-TAB 7.3, Schedule 5
22	Transportation Costs		2,585	40.2	103,917	2,585	40.2	103,917	2,585	40.2	103,917	- Sect 7-TAB 7.3, Schedule 6
23	Gas Purchases (excl Royalty Credits)		3,562	40.2	143,192	3,493	40.2	140,419	3,455	40.2	138,891	
24												
25	Taxes Other Than Income											- Sect 7-TAB 7.3, Schedule 24
26	Property Taxes		334	2.6	868	236	2.6	614	244	2.6	634	- Sect 7-TAB 7.3, Schedule 25
27	Carbon Tax		816	29.5	24,079	978	29.5	28,845	1,056	29.5	31,138	
28	HST - Net	*	218	39.8	8,671	520	39.8	20,708	556	39.8	22,118	
29	PST Component of HST (REC)	*	205	37.1	7,617	(104)	34.8	(3,605)	(115)	34.8	(4,003)	- Sect 7-TAB 7.3, Schedule 30
30	Income Tax		359	15.2	5,457	336	15.2	5,107	542	15.2	8,238	- Sect 7-TAB 7.3, Schedule 31
31												- Sect 7-TAB 7.3, Schedule 32
32	Total		$ 8,826	36.3	$ 320,543	$ 8,824	36.7	$ 323,893	$ 9,109	36.1	$ 329,108	

* 2011 was calculated using prior approved GST and PST method

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Plant & Equipment						
2	Net Book Value *	$ (13,456)	$ -	$ (13,483)	$ (14,071)	$ (14,133)	
3	Less: Undepreciated Capital Cost	(13,740)	-	(13,620)	(13,888)	(13,675)	
4		284	-	137	(183)	(458)	
5	Weighted Average Future Tax Rate	24.28%	0.00%	25.00%	25.00%	25.00%	
6		69	-	34	(46)	(115)	
7							
8	Total FIT Liability- After Tax (PP&E)	69	-	34	(46)	(115)	
9	Total FIT Liability- After Tax (Non-PP&E)	(1,532)	-	(1,599)	(1,648)	(1,671)	
10	Total FIT Liability- After Tax	(1,463)	-	(1,565)	(1,694)	(1,786)	
11							
12	Tax Gross Up	(469)	-	(522)	(565)	(595)	
13							
14	FIT Liability/Asset - End of Year	(1,932)	-	(2,086)	(2,258)	(2,381)	
15							
16	FIT Liability/Asset - Opening Balance	(1,668)	-	(1,932)	(2,086)	(2,258)	
17							- Sect 7-TAB 7.3, Schedule 39
18	FIT Liability/Asset - Mid Year	$ (1,800)	$ -	$ (2,009)	$ (2,172)	$ (2,319)	- Sect 7-TAB 7.3, Schedule 40
19							- Sect 7-TAB 7.3, Schedule 41
20							
21	Note: * Excludes Land, Software CIAC, and WIP.						

($000s)

Line No.	Particulars	Capitalization Amount (2)	Capitalization Amount (3)	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 RATES							
2	Long-Term Debt		$ 20,000	44.55%	5.11%	2.28%	$ 1,022	- Sect 7-TAB 7.3, Schedule 82
3	Unfunded Debt		6,935	15.45%	5.15%	0.80%	357	
4	Common Equity		17,956	40.00%	8.50%	3.40%	1,531	
5								
6			$ 44,891	100.00%		6.48%	$ 2,909	- Sect 7-TAB 7.3, Schedule 39
7								
8								
9								
10	2011 REVISED RATES - PROJECTED							
11	Long-Term Debt		$ 20,000	44.55%	5.11%	2.28%	$ 1,022	- Sect 7-TAB 7.3, Schedule 82
12	Unfunded Debt	$ 6,935						
13	Adjustment, Revised Rates	-	6,935	15.45%	5.15%	0.80%	357	
14	Common Equity		17,956	40.00%	8.51%	3.40%	1,531	
15								- Sect 7-TAB 7.3, Schedule 4
16			$ 44,891	100.00%		6.48%	$ 2,909	- Sect 7-TAB 7.3, Schedule 39

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2012 AT 2011 RATES							
2	Long-Term Debt		$ 20,000	47.47%	5.11%	2.43%	$ 1,022	- Sect 7-TAB 7.3, Schedule 83
3	Unfunded Debt		5,282	12.53%	3.75%	0.47%	198	
4	Common Equity		16,854	40.00%	9.23%	3.69%	1,557	
5								
6			$ 42,136	100.00%		6.59%	$ 2,777	- Sect 7-TAB 7.3, Schedule 40
7								
8								
9								
10	2012 REVISED RATES							
11	Long-Term Debt		$ 20,000	47.46%	5.11%	2.43%	$ 1,022	- Sect 7-TAB 7.3, Schedule 83
12	Unfunded Debt	$ 5,282						
13	Adjustment, Revised Rates	1	5,283	12.54%	3.75%	0.47%	198	
14	Common Equity		16,856	40.00%	10.00%	4.00%	1,686	
15								- Sect 7-TAB 7.3, Schedule 5
16			$ 42,139	100.00%		6.90%	$ 2,906	- Sect 7-TAB 7.3, Schedule 40

($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 AT 2011 RATES							
2	Long-Term Debt		$ 20,000	48.21%	5.11%	2.46%	$ 1,022	- Sect 7-TAB 7.3, Schedule 84
3	Unfunded Debt		4,892	11.79%	4.75%	0.56%	232	
4	Common Equity		16,594	40.00%	5.13%	2.06%	852	
5								
6			$ 41,483	100.00%		5.07%	$ 2,105	- Sect 7-TAB 7.3, Schedule 41
7								
8								
9								
10	2013 REVISED RATES							
11	Long-Term Debt		$ 20,000	48.19%	5.11%	2.46%	$ 1,022	- Sect 7-TAB 7.3, Schedule 84
12	Unfunded Debt	$ 4,892						
13	Adjustment, Revised Rates	9	4,901	11.81%	4.75%	0.56%	233	
14	Common Equity		16,601	40.00%	10.00%	4.00%	1,660	
15								- Sect 7-TAB 7.3, Schedule 6
16			$ 41,502	100.00%		7.02%	$ 2,915	- Sect 7-TAB 7.3, Schedule 41

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	FEW Intercompany Loan	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000	5.110%	20,000	1,022
2	Total								$ 20,000	$ 1,022
3										
4									Average Embedded Cost	5.11%
5										
6	Cross Reference								- Sect 7-TAB 7.3, Schedule 79	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1										
2	FEW Intercompany Loan	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000	5.110%	20,000	1,022
3										
4	Total								$ 20,000	$ 1,022
5										
6									Average Embedded Cost	5.11%
7										
8	Cross Reference								- Sect 7-TAB 7.3, Schedule 80	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars (1)	Issue Date (2)	Maturity Date (3)	Coupon Rate (4)	Principal Amount of Issue (5)	Issue Expense (6)	Net Proceeds of Issue (7)	Effective Interest Cost (8)	Average Principal Outstanding (9)	Annual Cost (10)
1										
2	FEW Intercompany Loan	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000	5.110%	20,000	1,022
3										
4	Total								$ 20,000	$ 1,022
5										
6									Average Embedded Cost	5.11%
7										
8	Cross Reference								- Sect 7-TAB 7.3, Schedule 81	

FORTISBC ENERGY (Whistler) INC. May 4, 2011 Section 7
TAB 7.3
Schedule 85

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 Volumes (TJ)	2013 Volumes (TJ)	2012 Amortization ($000s)	2013 Amortization ($000s)	2012 Amortization of RSAM Unit Rider ($/GJ)	2013 Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**RSAM (Rider 5) Calculation**						
2							
3	SGS 1/2 RES	236.9	243.6			$0.524	$0.529
4	SGS 1/2 COMM	74.9	85.2			$0.524	$0.529
5	LGS 1	139.6	145.3			$0.524	$0.529
8	LGS 2	122.5	115.7			$0.524	$0.529
9	LGS 3	142.1	118.7			$0.524	$0.529
10							
11		716.0	708.5	$375	$375 (1)		

12
13
14 Note 1: RSAM Rider Change
15
16 In 2011, FortisBC (Whistler) Energy forecasts that there will be approximately $227 thousand (net-of-tax) of RSAM
17 additions. After offsetting the 2011 RSAM Rider recovery, the RSAM account including interest is now projected
18 to be a debit balance of $378 thousand on a net-of-tax basis by the end of 2011. The RSAM balance is to be amortized
19 over three years. Accordingly, the net-of-tax RSAM balance to be amortized in each year in 2012 and 2013 is
20 a debit of $281 thousand and $280 thousand, respectively. On a pre-tax basis, this amounts to $375 thousand, equivalent
21 to a charge to the customer of $0.524/GJ in 2012. The corresponding 2013 charge to the customer is $0.529/GJ."
22
23
24 2012 Net-Of-Tax Amortization = 1/3 of the sum of Projected December 31, 2011 RSAM Balance plus 2012 Opening Balance Adjustment
25 = 1/3 * ($843 RSAM + $-1 RSAM Interest)
26 = 1/3 * $842
27 = $281 Net-of-tax amortization
28
29 2012 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
30 = $281 / (1 - 25%)
31 = $375 Pre-tax amortization
32
33 2013 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2012 RSAM Balance
34 = 1/2 * ($562 RSAM + $-2 RSAM Interest)
35 = 1/2 * $560
36 = $280 Net-of-tax amortization
37
38 2013 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
39 = $280 / (1 - 25%)
40 = $375 Pre-tax amortization

7.4 Fort Nelson Schedules

Summary of Rate Change May 4, 2011 Section 7
TAB 7.4
Schedule 1

Fort Nelson

	2012 ($ thousands)		2013 ($ thousands)		Total ($ thousands)		Cross Reference
Volume/Revenue Related							
Customer Growth and Use Rates	$ (111.5)		$ (27.0)		$ (138.5)		
Change in Other Revenue	35.5	(76.0)	-	(27.0)	35.5	(103.0)	
O&M Changes							
Gross O&M Increases	53.8		31.1		84.9		
Less: Capitalized Overhead	(7.5)	46.3	(4.4)	26.8	(11.9)	73.0	
Depreciation & Removal Cost Provision							
Change in Depreciation Rates	(30.0)		-		(30.0)		
Tax Expense Impact of Depreciation Changes	12.6		3.3		15.9		
Depreciation from Net Additions	67.7		10.0		77.7		
Removal Cost Provision	-	50.3	-	13.3	-	63.6	
Amortization Expense							
CIAC	28.9		-		28.9		
Deferral Accounts	(66.3)	(37.4)	-	-	(66.3)	(37.4)	
Other							
Property and Other Taxes	6.8		6.0		12.8		
Other (NSP Provision, Transportation Costs)	-		-		-		
Income Tax Rate Change	(4.9)		0.4		(4.5)		
Other Income Tax Changes	(32.3)		(4.8)		(37.1)		
Financing Rate Changes	(14.3)		3.5		(10.8)		
Financing Changes	106.2		5.5		111.7		
Rate Base Growth	77.9	139.4	9.0	19.7	86.9	159.1	
Revenue Deficiency (Surplus)		**$ 122.6**		**$ 32.8**		**$ 155.4**	- Sect 7-TAB 7.4, Schedule 2 & 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Non-Bypass Sales	2012 Non-Bypass Transportation	2012 Bypass and Special Rates	2012 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 4,704	$ 4,633	$ 141	$ -	$ 4,774	$ 70	- Sect 7-TAB 7.4, Schedule 11
5								
6	Total Revenue	4,704	4,633	141	-	4,774	70	
7								
8	Less - Cost of Gas	(2,860)	(2,897)	(3)	-	(2,900)	(40)	- Sect 7-TAB 7.4, Schedule 13
9								
10	Gross Margin	$ 1,844	$ 1,736	$ 138	$ -	$ 1,874	$ 30	
11								
12	Revenue Deficiency (Surplus)	$ -	$ 113	$ 9	$ -	**$ 122**	$ 122	
13								
14	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	6.51%	6.52%	0.00%	6.51%		
15								
16	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	2.44%	6.38%	0.00%	2.56%		
17								

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Non-Bypass Sales	2013 Non-Bypass Transportation	2013 Bypass and Special Rates	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 4,774	$ 4,705	$ 141	$ -	$ 4,846	$ 72	- Sect 7-TAB 7.4, Schedule 12
5								
6	Total Revenue	4,774	4,705	141	-	4,846	72	
7								
8	Less - Cost of Gas	(2,900)	(2,942)	(3)	-	(2,945)	(45)	- Sect 7-TAB 7.4, Schedule 13
9								
10	Gross Margin	$ 1,874	$ 1,763	$ 138	$ -	$ 1,901	$ 27	
11								
12	Revenue Deficiency (Surplus)	$ 122	$ 144	$ 11	$ -	**$ 155**	$ 33	
13								
14	Revenue Deficiency (Surplus) as a % of Gross Margin	6.51%	8.17%	7.97%	0.00%	8.15%		
15								
16	Revenue Deficiency (Surplus) as a % of Total Revenue	2.56%	3.06%	7.80%	0.00%	3.20%		
17								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	ENERGY VOLUMES (TJ)					
2	Sales	560	549	569	20	- Sect 7-TAB 7.4, Schedule 7
3	Transportation	55	50	55	5	- Sect 7-TAB 7.4, Schedule 7
4		615	598	624	26	
5						
6	Average Rate per GJ					
7	Sales	$ 8.554	$ 8.771	$ 8.019	$ (0.752)	
8	Transportation	$ 2.127	$ 2.619	$ 2.564	$ (0.055)	
9	Average	$ 7.880	$ 8.261	$ 7.463	$ (0.798)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 4,790	$ 4,519	$ 4,563	$ 44	- Sect 7-TAB 7.4, Schedule 10
13	- Increase / (Decrease)	-	293	-	(293)	
14	RSAM Revenue	(61)	-	(47)	(47)	
15	Transportation - Existing Rates	117	108	141	33	- Sect 7-TAB 7.4, Schedule 10
16	- Increase / (Decrease)	-	22	-	(22)	
17						
18	**Total Revenue**	4,846	4,941	4,657	(284)	
19						
20	Cost of Gas Sold (Including Gas Lost)	3,409	3,179	2,860	(319)	- Sect 7-TAB 7.4, Schedule 13
21						
22	**Gross Margin**	1,437	1,763	1,797	35	
23						
24	Operation and Maintenance	680	698	699	1	- Sect 7-TAB 7.4, Schedule 21
25	Property and Sundry Taxes	158	165	170	5	- Sect 7-TAB 7.4, Schedule 24
26	Depreciation and Amortization	220	360	419	59	- Sect 7-TAB 7.4, Schedule 27
27	Other Operating Revenue	(29)	(60)	(24)	36	- Sect 7-TAB 7.4, Schedule 18
28	Sub-total	1,029	1,163	1,264	101	
29	Utility Income Before Income Taxes	409	599	533	(66)	
30						
31	Income Taxes	52	81	91	10	- Sect 7-TAB 7.4, Schedule 30
32						
33	**EARNED RETURN**	$ 357	$ 518	$ 442	$ (76)	- Sect 7-TAB 7.4, Schedule 79
34						
35						
36	**UTILITY RATE BASE**	$ 5,410	$ 6,839	$ 6,422	$ (417)	- Sect 7-TAB 7.4, Schedule 39
37						
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.60%	7.58%	6.88%	-0.69%	- Sect 7-TAB 7.4, Schedule 79

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 ------ Revised Rates ------- Revised Revenue	2012 ------ Revised Rates ------- Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (2))	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	569	577	-	577	8	- Sect 7-TAB 7.4, Schedule 8
3	Transportation	55	55	-	55	-	- Sect 7-TAB 7.4, Schedule 8
4		624	632	-	632	8	
5							
6	Average Rate per GJ						
7	Sales	$ 8.019	$ 8.029	$ -	$ 8.225	$ 0.206	
8	Transportation	$ 2.564	$ 2.564	$ -	$ 2.727	$ 0.163	
9	Average	$ 7.463	$ 7.554	$ -	$ 7.747	$ 0.284	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 4,563	$ 4,633	$ -	$ 4,633	$ 70	- Sect 7-TAB 7.4, Schedule 11
13	- Increase / (Decrease)	-	-	113	113	113	- Sect 7-TAB 7.4, Schedule 14
14						-	
15	Transportation - Existing Rates	141	141	-	141	-	- Sect 7-TAB 7.4, Schedule 11
16	- Increase / (Decrease)	-		9	9	9	- Sect 7-TAB 7.4, Schedule 14
17							
18	**Total Revenue**	4,657	4,774	122	4,896	239	
19							
20	Cost of Gas Sold (Including Gas Lost)	2,860	2,900	-	2,900	40	- Sect 7-TAB 7.4, Schedule 13
21							
22	**Gross Margin**	1,797	1,874	122	1,996	199	
23							
24	Operation and Maintenance	699	744	-	744	45	- Sect 7-TAB 7.4, Schedule 21
25	Property and Sundry Taxes	170	172	-	172	2	- Sect 7-TAB 7.4, Schedule 25
26	Depreciation and Amortization	419	360	-	360	(59)	- Sect 7-TAB 7.4, Schedule 28
27	Other Operating Revenue	(24)	(24)	-	(24)	-	- Sect 7-TAB 7.4, Schedule 19
28	Sub-total	1,264	1,252	-	1,252	(12)	
29	Utility Income Before Income Taxes	533	622	122	744	211	
30							
31	Income Taxes	91	26	30	56	(35)	- Sect 7-TAB 7.4, Schedule 31
32							
33	**EARNED RETURN**	$ 442	$ 596	$ 92	$ 688	$ 246	- Sect 7-TAB 7.4, Schedule 80
34							
35							
36	**UTILITY RATE BASE**	$ 6,422	$ 8,888	$ 1	$ 8,889	$ 2,467	- Sect 7-TAB 7.4, Schedule 40
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.88%	6.71%		7.74%	0.86%	- Sect 7-TAB 7.4, Schedule 80

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Revised Rates Revised Revenue	2013 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (2))	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	577	586	-	586	9	- Sect 7-TAB 7.4, Schedule 9
3	Transportation	55	55	-	55	-	- Sect 7-TAB 7.4, Schedule 9
4		632	641	-	641	9	
5							
6	Average Rate per GJ						
7	Sales	$ 8.225	$ 8.029	$ -	$ 8.275	$ 0.050	
8	Transportation	$ 2.727	$ 2.564	$ -	$ 2.764	$ 0.037	
9	Average	$ 7.747	$ 7.560	$ -	$ 7.802	$ 0.055	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 4,633	$ 4,705	$ -	$ 4,705	$ 72	- Sect 7-TAB 7.4, Schedule 12
13	- Increase / (Decrease)	113	-	144	144	31	- Sect 7-TAB 7.4, Schedule 16
14						-	
15	Transportation - Existing Rates	141	141	-	141	-	- Sect 7-TAB 7.4, Schedule 12
16	- Increase / (Decrease)	9		11	11	2	- Sect 7-TAB 7.4, Schedule 16
17							
18	**Total Revenue**	4,896	4,846	155	5,001	105	
19							
20	Cost of Gas Sold (Including Gas Lost)	2,900	2,945	-	2,945	45	- Sect 7-TAB 7.4, Schedule 13
21							
22	**Gross Margin**	1,996	1,901	155	2,056	60	
23							
24	Operation and Maintenance	744	771	-	771	27	- Sect 7-TAB 7.4, Schedule 21
25	Property and Sundry Taxes	172	178	-	178	6	- Sect 7-TAB 7.4, Schedule 26
26	Depreciation and Amortization	360	370	-	370	10	- Sect 7-TAB 7.4, Schedule 29
27	Other Operating Revenue	(24)	(24)	-	(24)	-	- Sect 7-TAB 7.4, Schedule 20
28	Sub-total	1,252	1,295	-	1,295	43	
29	Utility Income Before Income Taxes	744	606	155	761	17	
30							
31	Income Taxes	56	16	39	55	(1)	- Sect 7-TAB 7.4, Schedule 32
32							
33	**EARNED RETURN**	$ 688	$ 590	$ 116	$ 706	$ 18	- Sect 7-TAB 7.4, Schedule 81
34							
35							
36	**UTILITY RATE BASE**	$ 8,889	$ 9,123	$ 3	$ 9,126	$ 237	- Sect 7-TAB 7.4, Schedule 41
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.74%	6.47%		7.74%	0.00%	- Sect 7-TAB 7.4, Schedule 81

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	271.0	263.4	272.6	-	272.6	9.2	
3	Schedule 2.1 - Commercial	194.0	190.8	198.4		198.4	7.6	
4	Schedule 2.2 - Commercial	95.0	94.4	97.9		97.9	3.5	
5								
6	Total Sales	560.0	548.6	568.9	-	568.9	20.3	- Sect 7-TAB 7.4, Schedule 4
7								
8	**TRANSPORTATION SERVICE**							
9	Schedule 25 - Transportation Service	55.0	49.5	55.1	-	55.1	5.6	
10								
11	Total Transportation Service	55.0	49.5	55.1	-	55.1	5.6	- Sect 7-TAB 7.4, Schedule 4
12								
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	615.0	598.1	624.0	-	624.0	25.9	- Sect 7-TAB 7.4, Schedule 4

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2012

Line No.	Particulars	2011 PROJECTED	2012 Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	272.6	273.2	-	273.2	0.6	
3	Schedule 2.1 - Commercial	198.4	203.2		203.2	4.8	
4	Schedule 2.2 - Commercial	97.9	101.0		101.0	3.1	
5							
6	Total Sales	568.9	577.4	-	577.4	8.5	- Sect 7-TAB 7.4, Schedule 5
7							
8	**TRANSPORTATION SERVICE**						
9	Schedule 25 - Transportation Service	55.1	55.1	-	55.1	-	
10							
11	Total Transportation Service	55.1	55.1	-	55.1	-	- Sect 7-TAB 7.4, Schedule 5
12							
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	624.0	632.5	-	632.5	8.5	- Sect 7-TAB 7.4, Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 FORECAST	2013 Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	273.2	274.3	-	274.3	1.1	
3	Schedule 2.1 - Commercial	203.2	207.8		207.8	4.6	
4	Schedule 2.2 - Commercial	101.0	104.3		104.3	3.3	
5							
6	Total Sales	577.4	586.4	-	586.4	9.0	- Sect 7-TAB 7.4, Schedule 6
7							
8	**TRANSPORTATION SERVICE**						
9	Schedule 25 - Transportation Service	55.1	55.1	-	55.1	-	
10							
11	Total Transportation Service	55.1	55.1	-	55.1	-	- Sect 7-TAB 7.4, Schedule 6
12							
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	632.5	641.5	-	641.5	9.0	- Sect 7-TAB 7.4, Schedule 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	**SALES**							
2	Schedule 1 - Residential	$ 2,286	$ 2,137	$ 2,143	$ -	$ 2,143	$ 6	
3	Schedule 2.1 - Commercial	1,707	1,620	1,655		1,655	35	
4	Schedule 2.2 - Commercial	797	762	765		765	3	
5								
6	Total Sales	4,790	4,519	4,563	-	4,563	44	- Sect 7-TAB 7.4, Schedule 4
7								
8	**Transportation Service**							
9	Schedule 25 - Transportation Service	117	108	141	-	141	33	
10	Total Transportation Service	117	108	141	-	141	33	
11								
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,907	$ 4,627	$ 4,704	$ -	$ 4,704	$ 77	- Sect 7-TAB 7.4, Schedule 4

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 2,143	$ 2,149	$ -	$ 2,149	$ 6	
3	Schedule 2.1 - Commercial	1,655	1,694		1,694	39	
4	Schedule 2.2 - Commercial	765	790		790	25	
5							
6	Total Sales	4,563	4,633	-	4,633	70	- Sect 7-TAB 7.4, Schedule 5
7							
8	**Transportation Service**						
9	Schedule 25 - Transportation Service	141	141	-	141	-	
10	Total Transportation Service	141	141	-	141	-	
11							- Sect 7-TAB 7.4, Schedule 5
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,704	$ 4,774	$ -	$ 4,774	$ 70	- Sect 7-TAB 7.4, Schedule 15

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Gas Sales Revenue At Existing 2011 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 2,149	$ 2,157	$ -	$ 2,157	$ 8	
3	Schedule 2.1 - Commercial	1,694	1,733		1,733	39	
4	Schedule 2.2 - Commercial	790	815		815	25	
5							
6	Total Sales	4,633	4,705	-	4,705	72	- Sect 7-TAB 7.4, Schedule 6
7							
8	**Transportation Service**						
9	Schedule 25 - Transportation Service	141	141	-	141	-	
10	Total Transportation Service	141	141	-	141	-	
11							- Sect 7-TAB 7.4, Schedule 6
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,774	$ 4,846	$ -	$ 4,846	$ 72	- Sect 7-TAB 7.4, Schedule 17

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Gas Costs Non-Bypass Sales & Transp	2011 Bypass and Special Rates	2011 Total	2012 Gas Costs Non-Bypass Sales & Transp	2012 Bypass and Special Rates	2012 Total	2013 Gas Costs Non-Bypass Sales & Transp	2013 Bypass and Special Rates	2013 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**SALES**									
2	Schedule 1 - Residential	1,367	$ -	$ 1,367	$ 1,371	$ -	$ 1,371	1,376	$ -	$ 1,376
3	Schedule 2.1 - Commercial	996		996	1,019		1,019	1,043		1,043
4	Schedule 2.2 - Commercial	491		491	507		507	523		523
5										
6	Total Sales	2,854	-	2,854	2,897	-	2,897	2,942	-	2,942
7										
8	**TRANSPORTATION SERVICE**									
9	Schedule 25 - Transportation Service	6	-	6	3	-	3	3	-	3
10										
11	Total Transportation Service	6	-	6	3	-	3	3	-	3
12										
13	TOTAL SALES AND TRANSPORTATION SERVICES	$ 2,860	$ -	$ 2,860	$ 2,900	$ -	$ 2,900	$ 2,945	$ -	$ 2,945
14										
15	Cross Reference			- Sect 7-TAB 7.4, Schedule 4			- Sect 7-TAB 7.4, Schedule 5			- Sect 7-TAB 7.4, Schedule 6

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000s)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) 6.51% of Margin $/GJ	Revenue ($000s)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	273.2	$ 7.883	$ 2,149	$ 2.854	$ 778	$ 0.187	$ 51	1,942	$ 8.070	$ 2,200
4	Schedule 2.1 - Commercial	203.2	8.538	1,694	3.402	675	0.222	44	433	8.760	1,738
5	Schedule 2.2 - Commercial	101.0	8.069	790	2.891	283	0.184	18	28	8.253	808
6											
7	Total Sales	577.4		4,633		1,736		113	2,403		4,746
8											
9	TRANSPORTATION SERVICE										
10	Schedule 25 - Transportation Service	55.1	2.559	141	2.505	138	0.163	9	2	2.722	150
11											
12	Total Transportation Service	55.1		141		138		9	2		150
13											
14	Total Non-Bypass Sales & Transportation Service	632.5		$ 4,774		$ 1,874		$ 122	2,405		$ 4,896
15											
16	Cross Reference	- Sect 7-TAB 7.4, Schedule 8		- Sect 7-TAB 7.4, Schedule 11				- Sect 7-TAB 7.4, Schedule 2			
	control checks:	TGINBPvolume		TGINBPrev		TGINBPmargin		[revenue_deficiency]	AVG customers		
	[Input_FIS] non-bypass	632.5		4,774		1,875		122	2,405		
	Difference - over/(under)	-		0.2		0.6		-	0.3		

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2012 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

			Revenue -- At Existing 2011 Rates --		Gross Margin -- At Existing 2011 Rates --		Increase / (Decrease) 6.51% of Margin			Revenue ------ Revised Rates -------	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1											
2	**BYPASS AND SPECIAL RATES**										
3	Total Bypass Sales and										
4	Transportation Service	-		-		-		-	-		-
5											
6	TOTAL NON-BYPASS AND BYPASS SALES AND										
7	TRANSPORTATION SERVICE	632.5		$ 4,774		$ 1,874		$ 122	2,405		$ 4,896
8											
9	Cross Reference	- Sect 7-TAB 7.4, Schedule 8		- Sect 7-TAB 7.4, Schedule 11				- Sect 7-TAB 7.4, Schedule 2			

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

			Revenue		Gross Margin		Effective Increase / (Decrease)			Revenue	
			-- At Existing 2011 Rates --		-- At Existing 2011 Rates --		8.17%	of Margin	Average	------ Revised Rates -------	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	274.3	$ 7.913	$ 2,157	$ 2.865	$ 781	$ 0.235	$ 64	1,953	$ 8.148	$ 2,221
4	Schedule 2.1 - Commercial	207.8	8.735	1,733	3.483	691	0.282	56	444	9.017	1,789
5	Schedule 2.2 - Commercial	104.3	8.325	815	2.983	292	0.245	24	28	8.570	839
6											
7	Total Sales	586.4		4,705		1,764		144	2,425		4,849
8											
9	TRANSPORTATION SERVICE										
10	Schedule 25 - Transportation Service	55.1	2.559	141	2.505	138	0.200	11	2	2.759	152
11											
12	Total Transportation Service	55.1		141		138		11	2		152
13											
14	Total Non-Bypass Sales & Transportation Service	641.5		$ 4,846		$ 1,902		$ 155	2,427		$ 5,001
15											
16	Cross Reference	- Sect 7-TAB 7.4, Schedule 9		- Sect 7-TAB 7.4, Schedule 12				- Sect 7-TAB 7.4, Schedule 3			
	control checks:	TGINBPvolume		TGINBPrev		TGINBPmargin		[revenue_deficiency]	AVG customers		
	[Input_FIS] non-bypas:	641.5		4,846		1,902		155	2,428		
	Difference - over/(under)	-		0.4		(0.3)		-	0.5		

REVENUE UNDER EXISTING 2011 RATES AND REVISED 2013 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2011 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2011 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 8.17% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue ------ Revised Rates ------- Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1											
2	**BYPASS AND SPECIAL RATES**										
3	Total Bypass Sales and										
4	Transportation Service	-		-		-		-	-		-
5											
6	TOTAL NON-BYPASS AND BYPASS SALES AND										
7	TRANSPORTATION SERVICE	641.5		$ 4,846		$ 1,902		$ 155	2,427		$ 5,001
8											
9	Cross Reference	- Sect 7-TAB 7.4, Schedule 9		- Sect 7-TAB 7.4, Schedule 12				- Sect 7-TAB 7.4, Schedule 3			

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 18	$ 38	$ 13	$ (25)	- Sect 7-TAB 7.4, Schedule 76
4						
5	Connection Charge	11	20	11	(9)	- Sect 7-TAB 7.4, Schedule 76
6						
7	Other Recoveries	-	2	-	(2)	- Sect 7-TAB 7.4, Schedule 76
8						
9	**Total Other Operating Revenue**	$ 29	$ 60	$ 24	$ (36)	- Sect 7-TAB 7.4, Schedule 4

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 13	$ 13	$ -	- Sect 7-TAB 7.4, Schedule 76
4					
5	Connection Charge	11	11	-	- Sect 7-TAB 7.4, Schedule 76
6					
7	Other Recoveries	-	-	-	- Sect 7-TAB 7.4, Schedule 76
8					
9	**Total Other Operating Revenue**	$ 24	$ 24	$ -	- Sect 7-TAB 7.4, Schedule 5

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 13	$ 13	$0	- Sect 7-TAB 7.4, Schedule 76
4					
5	Connection Charge	11	11	-	- Sect 7-TAB 7.4, Schedule 76
6					
7	Other Recoveries	-	-	-	- Sect 7-TAB 7.4, Schedule 76
8					
9	**Total Other Operating Revenue**	$ 24	$ 24	$ -	- Sect 7-TAB 7.4, Schedule 6

FORTISBC ENERGY INC. - Fort Nelson May 4, 2011 Section 7
TAB 7.4
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW Schedule 21
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 126	$ 141	$ 141	$ 167	$ 171	
2	COPE Costs	55	68	68	75	79	
3	COPE Customer Services Costs	-	-	-	35	34	
4	IBEW Costs	267	258	258	269	276	
5							
6	**Labour Costs**	**448**	**467**	**467**	**547**	**558**	
7							
8	Vehicle Costs	52	61	61	49	50	
9	Employee Expenses	19	17	17	19	20	
10	Materials and Supplies	16	14	14	15	15	
11	Computer Costs	29	34	34	42	44	
12	Fees and Administration Costs *	68	60	60	175	190	
13	Contractor Costs *	172	177	177	43	46	
14	Facilities	35	42	42	45	41	
15	Recoveries & Revenue	(45)	(56)	(58)	(70)	(68)	
16							
17	**Non-Labour Costs**	**346**	**348**	**346**	**318**	**338**	
18							
19							
20	**Total Gross O&M Expenses**	**794**	**815**	**812**	**865**	**897**	
21							
22	Add: PST Savings	-	(3)	(0)	0	(0)	
23	Less: Capitalized Overhead	(114)	(114)	(114)	(121)	(126)	
24							- Sect 7-TAB 7.4, Schedule 4
25	**Total O&M Expenses**	**$ 680**	**$ 698**	**$ 699**	**$ 744**	**$ 771**	- Sect 7-TAB 7.4, Schedule 5
26	* Note: 2012 & 2013 reflect customer service costs previously contracted						- Sect 7-TAB 7.4, Schedule 6

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 86	$ 99	$ 88	$ 94	$ 97	
2								
3	Operation Centre - Distribution	100-21	93	66	95	101	105	
4	Asset Management - Distribution	100-22	15	11	16	17	17	
5	Preventative Maintenance - Distribution	100-23	19	22	19	20	21	
6	Distribution Operations - General	100-24	49	53	51	54	56	
7	Meter Exchange	100-25	-	-	-	-	-	
8	Emergency Management	100-26	40	62	41	43	45	
9	Distribution Operations Total	100-20	216	215	221	236	244	
10								
11	Distribution Corrective - Meters	100-31	16	13	16	17	18	
12	Distribution Corrective - Propane	100-32	-	-	-	-	-	
13	Distribution Corrective - Leak Repair	100-33	12	11	12	13	13	
14	Distribution Corrective - Stations	100-34	5	6	6	6	6	
15	Distribution Corrective - General	100-35	3	3	4	4	4	
16	Distribution Maintenance Total	100-30	36	34	37	39	41	
17								
18	**Distribution Total**	**100**	**338**	**347**	**346**	**369**	**382**	
19								
20	Transmission Supervision	200-11	-	-	-	-	-	
21								
22	Pipeline Operation	200-21	-	-	-	-	-	
23	Right of Way	200-22	-	-	-	-	-	
24	Compression	200-23	-	-	-	-	-	
25	Gas Control	200-24	-	-	-	-	-	
26	Transmission Pipeline Integrity Project (TPIP)	200-25	-	-	-	-	-	
27	Transmission Operations Total	200-20	-	-	-	-	-	
28								
29	Pipeline - Maintenance	200-31	-	-	-	-	-	
30	Compression - Maintenance	200-32	-	-	-	-	-	
31	TPIP - Maintenance	200-33	-	-	-	-	-	
32	Transmission Maintenance Total	200-30	-	-	-	-	-	
33								
34	**Transmission Total**	**200**	**-**	**-**	**-**	**-**	**-**	
35								
36	LNG Plant Operations	300-11	-	-	-	-	-	
37	LNG Plant Maintenance	300-21	-	-	-	-	-	
38								
39	**LNG Plant Total**	**300**	**-**	**-**	**-**	**-**	**-**	
40								
41	Measurement Operations	400-11	-	-	-	-	-	
42	Measurement Maintenance	400-21	-	-	-	-	-	
43								
44	**Measurement Total**	**400**	**-**	**-**	**-**	**-**	**-**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Facilities Management	500-10	$ -	$ -	$ -	$ -	$ -	
2	Shops & Stores	500-20	-	-	-	-	-	
3	Operations Engineering	500-30	-	-	-	-	-	
4	Property Services	500-40	-	-	-	-	-	
5	System Integrity	500-50	-	-	-	-	-	
6	Environmental Health & Safety	500-60	-	-	-	-	-	
7	Operations Governance	500-70	-	-	-	-	-	
8	Energy Supply & Resource Development	500-80	-	-	-	-	-	
9	**General Operations Total**	**500**	**-**	**-**	**-**	**-**	**-**	
10								
11	Energy Efficiency	600-10	-	-	-	-	-	
12	Marketing - Supervision	600-20	-	-	-	-	-	
13	Corporate & Marketing Communications	600-30	-	-	-	-	-	
14	Marketing Planning & Development	600-40	-	-	-	-	-	
15	**Marketing Total**	**600**	**-**	**-**	**-**	**-**	**-**	
16								
17	Customer Care - Supervision	700-10	-	-	-	-	-	
18	Customer Contact	700-20	135	136	136	-	-	
19	Bad Debt Management and Administration	700-30	-	-	-	-	-	
20	Customer Management & Sales	700-40	-	-	-	-	-	
21	**Customer Care Total**	**700**	**135**	**136**	**136**	**-**	**-**	
22								
23	Business & IT Services - Supervision	800-10	-	-	-	-	-	
24	Application Management	800-20	-	-	-	-	-	
25	Infrastructure Management	800-30	-	-	-	-	-	
26	Procurement Services	800-40	-	-	-	-	-	
27	**Business & IT Services Total**	**800**	**-**	**-**	**-**	**-**	**-**	
28								
29	Administration & General	900-11	-	-	-	-	-	
30	Insurance	900-12	-	-	-	-	-	
31	Finance and Regulatory Affairs	900-13	-	-	-	-	-	
32	Shared Services Agreement	900-14	321	331	331	497	515	
33	Corporate Administration Total	900-10	321	331	331	497	515	
34	Forecasting	900-20	-	-	-	-	-	
35	Public Affairs	900-30	-	-	-	-	-	
36	Business Development	900-40	-	-	-	-	-	
37	Human Resources	900-50	-	-	-	-	-	
38	Other Post Employment Benefits (OPEB)	900-60	-	-	-	-	-	
39	**Administration & General Total**	**900**	**321**	**331**	**331**	**497**	**515**	
40								
41	**Total Gross O&M Expenses**		**794**	**815**	**812**	**865**	**897**	
42								
43	Add: PST Savings		-	(3)	(0)	0	(0)	
44	Less: Capitalized Overhead		(114)	(114)	(114)	(121)	(126)	
45								- Sect 7-TAB 7.4, Schedule 4
46	**Total O&M Expenses**		**$ 680**	**$ 698**	**$ 699**	**$ 744**	**$ 771**	- Sect 7-TAB 7.4, Schedule 5
47								- Sect 7-TAB 7.4, Schedule 6

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

				2011 PROJECTED			
Line No.	Particulars	2010 ACTUAL	2011 APPROVED	Total Expenses	Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 55	$ 58	$ 58	$ 58	$ 0	
4							
5	General, School and Other	103	108	110	110	2	
6							
7		158	165	168	168	3	
8							
9	Add / Less: Deferred Property Taxes	-	-	2	2	2	
10							
11	Total	$ 158	$ 165	$ 170	$ 170	$ 5	- Sect 7-TAB 7.4, Schedule 4

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Total Expenses	2012 Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 58	$ 55	$ 55	$ (3)	
4						
5	General, School and Other	110	117	117	7	
6						
7		168	172	172	4	
8						
9	Add / Less: Deferred Property Taxes	2	-	-	(2)	
10						
11	Total	$ 170	$ 172	$ 172	$ 2	- Sect 7-TAB 7.4, Schedule 5

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Total Expenses	2013 Revised Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 55	$ 55	$ 55	$ -	
4						
5	General, School and Other	117	123	123	6	
6						
7		172	178	178	6	
8						
9	Add / Less: Deferred Property Taxes	-	-	-	-	
10						
11	Total	$ 172	$ 178	$ 178	$ 6	- Sect 7-TAB 7.4, Schedule 6

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 249	$ 317	$ 349	$ 32	- Sect 7-TAB 7.4, Schedule 54
4						
5	Less: Amortization of Contributions in Aid of Construction	(27)	(29)	-	29	- Sect 7-TAB 7.4, Schedule 63
6		222	288	349	61	
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ (3)	$ 71	$ 70	$ (1)	- Sect 7-TAB 7.4, Schedule 67
11						
12	TOTAL	$ 220	$ 360	$ 419	$ 59	- Sect 7-TAB 7.4, Schedule 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 349	$ 355	$ 6	- Sect 7-TAB 7.4, Schedule 57
4					
5	Less: Amortization of Contributions in Aid of Construction	-	-	-	- Sect 7-TAB 7.4, Schedule 64
6		349	355	6	
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 70	$ 5	$ (65)	- Sect 7-TAB 7.4, Schedule 69
11					
12	TOTAL	$ 419	$ 360	$ (59)	- Sect 7-TAB 7.4, Schedule 5

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 355	$ 365	$ 10	- Sect 7-TAB 7.4, Schedule 60
4					
5	Less: Amortization of Contributions in Aid of Construction	-	-	-	- Sect 7-TAB 7.4, Schedule 65
6		355	365	10	
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 5	$ 5	$ -	- Sect 7-TAB 7.4, Schedule 71
11					
12	TOTAL	$ 360	$ 370	$ 10	- Sect 7-TAB 7.4, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing Rates	2011 PROJECTED ------ Revised Rates ------- Revised Revenue	2011 PROJECTED Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 357	$ 518	$ 442	$ -	$ 442	$ (76)	- Sect 7-TAB 7.4, Schedule 4
3	Deduct - Interest on Debt	(217)	(258)	(247)	-	(247)	11	- Sect 7-TAB 7.4, Schedule 79
4	Net Additions (Deductions)	(8)	(37)	57	-	57	94	- Sect 7-TAB 7.4, Schedule 33
5	Adjusted Taxable Income After Tax	$ 131	$ 223	$ 252	$ -	$ 252	$ 29	
6								
7	Current Income Tax Rate	28.50%	26.50%	26.50%	26.50%	26.50%	0.00%	
8	1 - Current Income Tax Rate	71.50%	73.50%	73.50%	73.50%	73.50%	0.00%	
9								
10	Taxable Income	$ 184	$ 304	$ 343	$ -	$ 343	$ 39	
11								
12								
13	Income Tax - Current	$ 52	$ 81	$ 91	$ -	$ 91	$ 10	
14								
15	**Total Income Tax**	$ 52	$ 81	$ 91	$ -	$ 91	$ 10	- Sect 7-TAB 7.4, Schedule 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing Rates	2012 Revised Rates Revised Revenue	2012 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 442	$ 596	$ 92	$ 688	$ 246	- Sect 7-TAB 7.4, Schedule 5
3	Deduct - Interest on Debt	(247)	(350)	-	(350)	(103)	- Sect 7-TAB 7.4, Schedule 80
4	Net Additions (Deductions)	57	(169)	-	(169)	(226)	- Sect 7-TAB 7.4, Schedule 34
5	Adjusted Taxable Income After Tax	$ 252	$ 77	$ 92	$ 169	$ (83)	
6							
7	Current Income Tax Rate	26.50%	25.00%	25.00%	25.00%	-1.50%	
8	1 - Current Income Tax Rate	73.50%	75.00%	75.00%	75.00%	1.50%	
9							
10	Taxable Income	$ 343	$ 103	$ 122	$ 225	$ (118)	
11							
12							
13	Income Tax - Current	$ 91	$ 26	$ 30	$ 56	$ (35)	
14							
15	**Total Income Tax**	$ 91	$ 26	$ 30	$ 56	$ (35)	- Sect 7-TAB 7.4, Schedule 5

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing Rates	2013 Revised Rates Revised Revenue	2013 Revised Rates Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 688	$ 590	$ 116	$ 706	$ 18	- Sect 7-TAB 7.4, Schedule 6
3	Deduct - Interest on Debt	(350)	(359)	-	(359)	(9)	- Sect 7-TAB 7.4, Schedule 81
4	Net Additions (Deductions)	(169)	(182)	-	(182)	(13)	- Sect 7-TAB 7.4, Schedule 35
5	Adjusted Taxable Income After Tax	$ 169	$ 49	$ 116	$ 165	$ (4)	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 225	$ 65	$ 155	$ 220	$ (5)	
11							
12							
13	Income Tax - Current	$ 56	$ 16	$ 39	$ 55	$ (1)	
14							
15	**Total Income Tax**	$ 56	$ 16	$ 39	$ 55	$ (1)	- Sect 7-TAB 7.4, Schedule 6

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 3	$ 3	$ -	$ (3)	
3	Depreciation	222	288	349	61	- Sect 7-TAB 7.4, Schedule 27
4	Amortization of Debt Issue Expenses	3	4	1	(3)	
5						
6	**Deductions:**					
7	Amortization of Deferred Charges	(3)	71	70	(1)	- Sect 7-TAB 7.4, Schedule 27
8	Capital Cost Allowance	(173)	(311)	(311)	(0)	- Sect 7-TAB 7.4, Schedule 36
9	Cumulative Eligible Capital Allowance	-	-	-	-	
10	Debt Issue Costs	(5)	(5)	(3)	2	
11	Vehicle Lease Payment	(8)	-	-	-	
12	Pension Contributions	(3)	(38)	-	38	
13	Overheads Capitalized Expensed for Tax Purposes	(41)	(49)	(49)	(0)	
14	Removal Costs	-	-	-	-	
15	Major Inspection Costs	(4)	-	-	-	
16						
17	TOTAL	$ (8)	$ (37)	$ 57	$ 94	- Sect 7-TAB 7.4, Schedule 30

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ -	$ 3	$ 3	
3	Depreciation	349	355	6	- Sect 7-TAB 7.4, Schedule 28
4	Amortization of Debt Issue Expenses	1	2	1	
5					
6	**Deductions:**				
7	Amortization of Deferred Charges	70	5	(65)	- Sect 7-TAB 7.4, Schedule 28
8	Capital Cost Allowance	(311)	(480)	(169)	- Sect 7-TAB 7.4, Schedule 37
9	Cumulative Eligible Capital Allowance	-	-	-	
10	Debt Issue Costs	(3)	(2)	1	
11	Vehicle Lease Payment	-	-	-	
12	Pension Contributions	-	-	-	
13	Overheads Capitalized Expensed for Tax Purposes	(49)	(52)	(3)	
14	Removal Costs	-	-	-	
15	Major Inspection Costs	-	-	-	
16					
17	TOTAL	$ 57	$ (169)	$ (226)	- Sect 7-TAB 7.4, Schedule 31

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 3	$ 3	$ -	
3	Depreciation	355	365	10	- Sect 7-TAB 7.4, Schedule 29
4	Amortization of Debt Issue Expenses	2	2	-	
5					
6	**Deductions:**				
7	Amortization of Deferred Charges	5	5	-	- Sect 7-TAB 7.4, Schedule 29
8	Capital Cost Allowance	(480)	(502)	(22)	- Sect 7-TAB 7.4, Schedule 38
9	Cumulative Eligible Capital Allowance	-	-	-	
10	Debt Issue Costs	(2)	(1)	1	
11	Vehicle Lease Payment	-	-	-	
12	Pension Contributions	-	-	-	
13	Overheads Capitalized Expensed for Tax Purposes	(52)	(54)	(2)	
14	Removal Costs	-	-	-	
15	Major Inspection Costs	-	-	-	
16					
17	TOTAL	$ (169)	$ (182)	$ (13)	- Sect 7-TAB 7.4, Schedule 32

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

* CAPITAL COST ALLOWANCE *

Line No.	Class	CCA Rate	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 2,669	$ -	$ -	$ (107)	$ 2,562
2	1(b)	6%	483	-	-	(29)	454
3	2	6%	307	-	-	(18)	289
4	3	5%	16	-	-	(1)	15
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	3	-	8	(1)	10
8	10	30%	3	-	-	(1)	2
9	12	100%	-	-	-	-	-
10	13	manual	1	-	-	(1)	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	82	220	(15)	287
17	49	8%	179	-	2,936	(132)	2,983
18	50 / 52	55% / 100%	-	-	-	-	-
19	51	6%	183	(82)	-	(6)	95
20	43.2	50%	-	-	-	-	-
21							
22		Total	$ 3,845	$ -	$ 3,164	$ (311)	$ 6,698
23							
24	Cross Reference					- Sect 7-TAB 7.4, Schedule 33	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	12/31/2011 UCC Balance	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 2,562	$ -	$ -	$ (102)	$ 2,460
2	1(b)	6%	454	-	-	(27)	427
3	2	6%	289	(1)	-	(17)	271
4	3	5%	15	-	-	(1)	14
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	10	-	10	(3)	17
8	10	30%	2	-	-	(1)	1
9	12	100%	-	-	-	-	-
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	287	-	201	(31)	457
17	49	8%	2,983	-	324	(252)	3,055
18	50	55%	-	-	144	(40)	104
19	51	6%	95	-	-	(6)	89
20	43.2	50%	-	-	-	-	-
21							
22		Total	$ 6,698	$ (1)	$ 679	$ (480)	$ 6,896
23							
24	Cross Reference					- Sect 7-TAB 7.4, Schedule 34	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 2,460	$ -	$ -	$ (98)	$ 2,362
2	1(b)	6%	427	-	-	(26)	401
3	2	6%	271	-	-	(16)	255
4	3	5%	14	-	-	(1)	13
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	17	-	10	(4)	23
8	10	30%	1	-	-	-	1
9	12	100%	-	-	-	-	-
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	457	(1)	325	(50)	731
17	49	8%	3,055	-	13	(245)	2,823
18	50	55%	104	-	-	(57)	47
19	51	6%	89	-	-	(5)	84
20	43.2	50%	-	-	-	-	-
21							
22		Total	$ 6,896	$ (1)	$ 348	$ (502)	$ 6,741
23							
24	Cross Reference					- Sect 7-TAB 7.4, Schedule 35	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	Gas Plant in Service, Beginning	$ 8,146	$ 8,809	$ 8,642	$ -	$ 8,642	$ (167)	- Sect 7-TAB 7.4, Schedule 45
2	Opening Balance Adjustment	-	-	-	-	-	-	
3	Gas Plant in Service, Ending	8,641	12,107	11,799	-	11,799	(308)	- Sect 7-TAB 7.4, Schedule 45
4								
5	Accumulated Depreciation Beginning - Plant	$ (2,033)	$ (2,342)	$ (2,213)	$ -	$ (2,213)	$ 129	- Sect 7-TAB 7.4, Schedule 54
6	Opening Balance Adjustment	-	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(2,214)	(2,630)	(2,366)	-	(2,366)	264	- Sect 7-TAB 7.4, Schedule 54
8								
9	Negative Salvage Depreciation Beginning - Pl	$ -	$ -	$ -	$ -	$ -	$ -	
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	Negative Salvage Depreciation Ending - Plant	-	-	-	-	-	-	
12								
13	CIAC, Beginning	$ (1,271)	$ (1,271)	$ (1,287)	$ -	$ (1,287)	$ (16)	- Sect 7-TAB 7.4, Schedule 63
14	Opening Balance Adjustment	-	-	-	-	-	-	
15	CIAC, Ending	(1,287)	(1,271)	(1,287)	-	(1,287)	(16)	- Sect 7-TAB 7.4, Schedule 63
16								
17	Accumulated Amortization Beginning - CIAC	$ 452	$ 541	$ 490	$ -	$ 490	$ (51)	- Sect 7-TAB 7.4, Schedule 63
18	Opening Balance Adjustment	-	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	490	570	490	-	490	(80)	- Sect 7-TAB 7.4, Schedule 63
20								
21	Net Plant in Service, Mid-Year	$ 5,462	$ 7,256	$ 7,134	$ -	$ 7,134	$ (122)	
22								
23	* Adjustment to 13-Month Average	(95)	(666)	(812)	-	(812)	(146)	
24	Work in Progress, No AFUDC	235	38	-	-	-	(38)	
25	Unamortized Deferred Charges	64	154	85	-	85	(69)	- Sect 7-TAB 7.4, Schedule 67
26	Cash Working Capital	(273)	54	11	-	11	(43)	- Sect 7-TAB 7.4, Schedule 72
27	Other Working Capital	17	3	4	-	4	1	- Sect 7-TAB 7.4, Schedule 72
28	**Utility Rate Base**	$ 5,410	$ 6,839	$ 6,422	$ -	$ 6,422	$ (417)	- Sect 7-TAB 7.4, Schedule 79
29								
30	* Note FEFN: Oct 2011 In-Service date applied to Muskwa River Crossing							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 FORECAST Existing 2011 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 8,642	$ 11,799	$ -	$ 11,799	$ 3,157	- Sect 7-TAB 7.4, Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	11,799	12,525	-	12,525	726	- Sect 7-TAB 7.4, Schedule 48
4							
5	Accumulated Depreciation Beginning - Plant	$ (2,213)	$ (2,366)	$ -	$ (2,366)	$ (153)	- Sect 7-TAB 7.4, Schedule 57
6	Opening Balance Adjustment (re Negative Salvage)	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 57
7	Accumulated Depreciation Ending - Plant	(2,366)	(2,718)	-	(2,718)	(352)	- Sect 7-TAB 7.4, Schedule 57
8							
9	Negative Salvage Depreciation Beginning - Plant	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.4, Schedule 61
10	Opening Balance Adjustment (re Negative Salvage)	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 61
11	Negative Salvage Depreciation Ending - Plant	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 61
12							
13	CIAC, Beginning	$ (1,287)	$ (1,287)	$ -	$ (1,287)	$ -	- Sect 7-TAB 7.4, Schedule 64
14	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 64
15	CIAC, Ending	(1,287)	(1,287)	-	(1,287)	-	- Sect 7-TAB 7.4, Schedule 64
16							
17	Accumulated Amortization Beginning - CIAC	$ 490	$ 490	$ -	$ 490	$ -	- Sect 7-TAB 7.4, Schedule 64
18	Opening Balance Adjustment	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 64
19	Accumulated Amortization Ending - CIAC	490	490	-	490	-	- Sect 7-TAB 7.4, Schedule 64
20							
21	Net Plant in Service, Mid-Year	$ 7,134	$ 8,823	$ -	$ 8,823	$ 1,689	
22							
23	* Adjustment to 13-Month Average	(812)	-	-	-	812	
24	Work in Progress, No AFUDC	-	-	-	-	-	
25	Unamortized Deferred Charges	85	54	-	54	(31)	- Sect 7-TAB 7.4, Schedule 69
26	Cash Working Capital	11	7	1	8	(3)	- Sect 7-TAB 7.4, Schedule 73
27	Other Working Capital	4	4	-	4	-	- Sect 7-TAB 7.4, Schedule 73
28	**Utility Rate Base**	$ 6,422	$ 8,888	$ 1	$ 8,889	$ 2,467	- Sect 7-TAB 7.4, Schedule 80
29							
30	* Note FEFN: Jan-12 In-Service date applied to Customer Care Enhancement						

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST Existing 2011 Rates	2013 FORECAST Adjustments	2013 FORECAST Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 11,799	$ 12,525	$ -	$ 12,525	$ 726	- Sect 7-TAB 7.4, Schedule 51
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	12,525	12,919	-	12,919	394	- Sect 7-TAB 7.4, Schedule 51
4							
5	Accumulated Depreciation Beginning - Plant	$ (2,366)	$ (2,718)	$ -	$ (2,718)	$ (352)	- Sect 7-TAB 7.4, Schedule 60
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(2,718)	(3,076)	-	(3,076)	(358)	- Sect 7-TAB 7.4, Schedule 60
8							
9	Negative Salvage Depreciation Beginning - Plant	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.4, Schedule 62
10	Opening Balance Adjustment	-	-	-	-	-	
11	Negative Salvage Depreciation Ending - Plant	-	-	-	-	-	- Sect 7-TAB 7.4, Schedule 62
12							
13	CIAC, Beginning	$ (1,287)	$ (1,287)	$ -	$ (1,287)	$ -	- Sect 7-TAB 7.4, Schedule 65
14	Opening Balance Adjustment	-	-	-	-	-	
15	CIAC, Ending	(1,287)	(1,287)	-	(1,287)	-	- Sect 7-TAB 7.4, Schedule 65
16							
17	Accumulated Amortization Beginning - CIAC	$ 490	$ 490	$ -	$ 490	$ -	- Sect 7-TAB 7.4, Schedule 65
18	Opening Balance Adjustment	-	-	-	-	-	
19	Accumulated Amortization Ending - CIAC	490	490	-	490	-	- Sect 7-TAB 7.4, Schedule 65
20							
21	Net Plant in Service, Mid-Year	$ 8,823	$ 9,028	$ -	$ 9,028	$ 205	
22							
23	Adjustment to 13-Month Average	-	-	-	-	-	
24	Work in Progress, No AFUDC	-	-	-	-	-	
25	Unamortized Deferred Charges	54	82	-	82	28	- Sect 7-TAB 7.4, Schedule 71
26	Cash Working Capital	8	9	3	12	4	- Sect 7-TAB 7.4, Schedule 74
27	Other Working Capital	4	4	-	4	-	- Sect 7-TAB 7.4, Schedule 74
28	**Utility Rate Base**	$ 8,889	$ 9,123	$ 3	$ 9,126	$ 237	- Sect 7-TAB 7.4, Schedule 81
29							
30							

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000)

Line No.	Particulars	2011 Projected	2012 Forecast	2013 Forecast	Reference
	(1)	(3)	(4)	(5)	(6)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4					
5	Total Regular Capital Expenditures	$ 2,799	$ 609	$ 276	
6					
7					
8	Special Projects - CPCN's	$ -	$ -	$ -	
9					
10					
11	TOTAL CAPITAL EXPENDITURES	$ 2,799	$ 609	$ 276	
12					
13					
14	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
15					
16	Regular Capital				
17	Regular Capital Expenditures	$ 2,799	$ 609	$ 276	
18	Add - Opening WIP	-	-	-	
19	Less - Opening WIP Adjustment	300	-	-	
20	Less - Closing WIP	-	-	-	
21	Add - AFUDC	152	-	-	- Sect 7-TAB 7.4, Schedule 45
22	Add - Overhead Capitalized	114	120	125	- Sect 7-TAB 7.4, Schedule 48
23					- Sect 7-TAB 7.4, Schedule 51
24	TOTAL PLANT ADDITIONS	$ 3,365	$ 729	$ 400	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	9	-	-	-	-	-	-	9	9
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	21	-	-	-	-	-	-	21	21
13	402-01 Application Software - 12.5%	-	-	-	-	-	-	-	-	-
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	30	-	-	-	-	-	-	30	30
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	-	-	-	-	-	-	-	-	-
6	464-00 Other Structures & Improvements	1	-	-	-	-	-	-	1	1
7	465-00 Mains	709	-	2,876	152	106	(29)	-	3,814	2,262
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	-	-	-	-	-	-	631	631
12	467-20 Telemetering	4	-	-	-	-	-	-	4	4
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	1,345	-	2,876	152	106	(29)	-	4,450	2,898
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	3	-	-	-	-	-	-	3	3
19	472-00 Structures & Improvements	247	-	-	-	-	-	-	247	247
20	473-00 Services	2,288	-	71	-	3	(16)	-	2,346	2,317
21	474-00 House Regulators & Meter Installations	530	-	4	-	-	-	-	534	532
22	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
23	475-00 Mains	2,021	-	51	-	2	-	-	2,074	2,048
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	999	-	85	-	3	-	-	1,087	1,043
26	477-00 Telemetering	14	-	-	-	-	-	-	14	14
27	478-10 Meters	24	-	4	-	-	-	-	28	26
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,126	-	215	-	8	(16)	-	6,333	6,230
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	2011 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	242	-	-	-	-	-	-	242	242
6	- Masonry Buildings	424	-	-	-	-	(146)	-	278	351
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	12	-	-	-	-	-	-	12	12
10	483-40 GP Furniture	25	-	-	-	-	-	-	25	25
11	483-10 GP Computer Hardware	182	-	-	-	-	-	-	182	182
12	483-20 GP Computer Software	130	-	-	-	-	-	-	130	130
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	11	-	-	-	-	-	-	11	11
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	-	-	-	-	-	-	3	3
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	84	-	8	-	-	-	-	92	88
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	(15)	-	(15)	(8)
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	25	-	-	-	-	-	-	25	25
24	- Radio	2	-	-	-	-	-	-	2	2
25	489-00 Other General Equipment	-	-	-	-	-	(2)	-	(2)	(1)
26	TOTAL GENERAL	1,141	-	8	-	-	(163)	-	986	1,064
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 8,642	$ -	$ 3,099	$ 152	$ 114	$ (208)	$ -	$ 11,799	$ 10,221
33										
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 39							- Sect 7-TAB 7.4, Schedule 39	
35			- Sect 7-TAB 7.4, Schedule 42							- Sect 7-TAB 7.4, Schedule 54

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	9	-	-	-	-	-	-	9	9
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	21	-	-	-	-	-	-	21	21
13	402-01 Application Software - 12.5%	-	-	-	-	-	-	-	-	-
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	30	-	-	-	-	-	-	30	30
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	-	-	-	-	-	-	-	-	-
6	464-00 Other Structures & Improvements	1	-	-	-	-	-	-	1	1
7	465-00 Mains	3,814	-	290	-	75	-	-	4,179	3,997
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	-	-	-	-	-	-	631	631
12	467-20 Telemetering	4	-	-	-	-	-	-	4	4
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	4,450	-	290	-	75	-	-	4,815	4,633
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	3	-	-	-	-	-	-	3	3
19	472-00 Structures & Improvements	247	-	-	-	-	-	-	247	247
20	473-00 Services	2,346	-	70	-	18	-	-	2,434	2,390
21	474-00 House Regulators & Meter Installations	534	-	4	-	1	-	-	539	537
22	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
23	475-00 Mains	2,074	-	52	-	13	-	-	2,139	2,107
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,087	-	50	-	13	-	-	1,150	1,119
26	477-00 Telemetering	14	-	-	-	-	-	-	14	14
27	478-10 Meters	28	-	4	-	-	-	-	32	30
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,333	-	180	-	45	-	-	6,558	6,446
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	242	-	-	-	-	-	-	242	242
6	- Masonry Buildings	278	-	129	-	-	-	-	407	343
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	12	-	-	-	-	-	-	12	12
10	483-40 GP Furniture	25	-	-	-	-	-	-	25	25
11	483-10 GP Computer Hardware	182	-	-	-	-	-	-	182	182
12	483-20 GP Computer Software	130	-	-	-	-	-	-	130	130
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	11	-	-	-	-	-	-	11	11
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	-	-	-	-	-	-	3	3
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	92	-	10	-	-	(3)	-	99	96
20	487-00 Equipment on Customer's Premises	(15)	-	-	-	-	-	-	(15)	(15)
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	25	-	-	-	-	-	-	25	25
24	- Radio	2	-	-	-	-	-	-	2	2
25	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
26	TOTAL GENERAL	986	-	139	-	-	(3)	-	1,122	1,054
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 11,799	$ -	$ 609	$ -	$ 120	$ (3)	$ -	$ 12,525	$ 12,162
33										
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 40							- Sect 7-TAB 7.4, Schedule 40	
35			- Sect 7-TAB 7.4, Schedule 42							- Sect 7-TAB 7.4, Schedule 57

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	-	-	-	-	-	-	-	-
4	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
5	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
6	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
8	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
10	461-00 Transmission Land Rights	9	-	-	-	-	-	-	9	9
11	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
12	471-00 Distribution Land Rights	21	-	-	-	-	-	-	21	21
13	402-01 Application Software - 12.5%	-	-	-	-	-	-	-	-	-
14	402-02 Application Software - 20%	-	-	-	-	-	-	-	-	-
15	TOTAL INTANGIBLE	30	-	-	-	-	-	-	30	30
16										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	-	-	-	-	-	-	-	-	-
6	464-00 Other Structures & Improvements	1	-	-	-	-	-	-	1	1
7	465-00 Mains	4,179	-	10	-	5	-	-	4,194	4,187
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	-	-	-	-	-	-	631	631
12	467-20 Telemetering	4	-	-	-	-	-	-	4	4
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	4,815	-	10	-	5	-	-	4,830	4,823
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	3	-	-	-	-	-	-	3	3
19	472-00 Structures & Improvements	247	-	-	-	-	-	-	247	247
20	473-00 Services	2,434	-	76	-	36	-	-	2,546	2,490
21	474-00 House Regulators & Meter Installations	539	-	4	-	2	-	-	545	542
22	477-00 Meters/Regulators Installations	-	-	-	-	-	-	-	-	-
23	475-00 Mains	2,139	-	147	-	70	-	-	2,356	2,248
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,150	-	25	-	12	-	-	1,187	1,169
26	477-00 Telemetering	14	-	-	-	-	-	-	14	14
27	478-10 Meters	32	-	4	-	-	-	-	36	34
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,558	-	256	-	120	-	-	6,934	6,746
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ 1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	242	-	-	-	-	-	-	242	242
6	- Masonry Buildings	407	-	-	-	-	-	-	407	407
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	12	-	-	-	-	-	-	12	12
10	483-40 GP Furniture	25	-	-	-	-	-	-	25	25
11	483-10 GP Computer Hardware	182	-	-	-	-	-	-	182	182
12	483-20 GP Computer Software	130	-	-	-	-	-	-	130	130
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	11	-	-	-	-	-	-	11	11
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	-	-	-	-	-	-	3	3
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	99	-	10	-	-	(7)	-	102	101
20	487-00 Equipment on Customer's Premises	(15)	-	-	-	-	-	-	(15)	(15)
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	25	-	-	-	-	-	-	25	25
24	- Radio	2	-	-	-	-	-	-	2	2
25	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
26	TOTAL GENERAL	1,122	-	10	-	-	(7)	-	1,125	1,124
27										
28	**UNCLASSIFIED PLANT**									
29	499 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 12,525	$ -	$ 276	$ -	$ 125	$ (7)	$ -	$ 12,919	$ 12,722
33										
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 41							- Sect 7-TAB 7.4, Schedule 41	
35			- Sect 7-TAB 7.4, Schedule 42						- Sect 7-TAB 7.4, Schedule 60	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	1.00%	-	-	-	-	-
4	178-00 Organization Expense	-	1.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	-	19.76%	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	23.66%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	2.14%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	9	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	21	0.00%	-	-	-	-	-
13	402-01 Application Software - 12.5%	-	12.50%	-	-	-	-	-
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	30		-	-	-	-	-

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.84%	-	-	-	-	-
5	463-00 Measuring Structures	-	4.27%	-	-	-	(3)	(3)
6	464-00 Other Structures & Improvements	1	2.88%	-	-	-	(2)	(2)
7	465-00 Mains	2,262	1.63%	37	-	(29)	37	45
8	465-00 Mains - INSPECTION	-	14.87%	-	-	-	-	-
9	466-00 Compressor Equipment	-	3.18%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	4.47%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	7.19%	45	-	-	43	88
12	467-20 Telemetering	4	1.33%	-	-	-	(2)	(2)
13	468-00 Communication Structures & Equipment	-	0.00%	-	-	-	-	-
14	TOTAL TRANSMISSION	2,898		82	-	(29)	73	126
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	3	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	247	3.60%	9	-	-	62	71
20	473-00 Services	2,317	2.25%	52	-	(4)	757	805
21	474-00 House Regulators & Meter Installations	532	5.21%	28	-	-	166	194
22	477-00 Meters/Regulators Installations	-	0.00%	-	-	-	-	-
23	475-00 Mains	2,048	1.89%	39	-	-	480	519
24	476-00 Compressor Equipment	-	25.04%	-	-	-	(97)	(97)
25	477-00 Measuring & Regulating Equipment	1,043	5.72%	60	-	-	292	352
26	477-00 Telemetering	14	0.25%	-	-	-	12	12
27	478-10 Meters	26	5.31%	1	-	-	3	4
28	478-20 Instruments	-	4.03%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,230		189	-	(4)	1,675	1,860
31								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	242	3.67%	9	-	-	9	18
6	- Masonry Buildings	351	2.50%	9	-	(146)	182	45
7	- Leasehold Improvement	-	0.00%	-	-	-	7	7
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	12	6.67%	1	-	-	20	21
10	483-40 GP Furniture	25	5.00%	1	-	-	-	1
11	483-10 GP Computer Hardware	182	20.00%	36	-	-	229	265
12	483-20 GP Computer Software	130	12.50%	16	-	-	7	23
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	11	7.70%	1	-	-	(26)	(25)
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	6.64%	-	-	-	(52)	(52)
18	485-20 Heavy Mobile Equipment	-	8.48%	-	-	-	-	-
19	486-00 Small Tools & Equipment	88	5.00%	4	-	-	55	59
20	487-00 Equipment on Customer's Premises	(8)	6.67%	(1)	-	(15)	-	(16)
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	25	6.67%	2	-	-	26	28
24	- Radio	2	6.67%	-	-	-	8	8
25	489-00 Other General Equipment	(1)	0.00%	-	-	(2)	-	(2)
26	TOTAL GENERAL	1,064		78	-	(163)	465	380
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 10,221		$ 349	$ -	$ (196)	$ 2,213	$ 2,366
33								
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 45		- Sect 7-TAB 7.4, Schedule 27			- Sect 7-TAB 7.4, Schedule 39	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust- ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	1.00%	-	-	-	-	-
4	178-00 Organization Expense	-	1.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	-	49.19%	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	57.14%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	2.38%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	9	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	21	0.00%	-	-	-	-	-
13	402-01 Application Software - 12.5%	-	12.50%	-	-	-	-	-
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	30		-	-	-	-	-

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.74%	-	-	-	-	-
5	463-00 Measuring Structures	-	3.80%	-	-	-	(3)	(3)
6	464-00 Other Structures & Improvements	1	2.83%	-	-	-	(2)	(2)
7	465-00 Mains	3,997	1.44%	58	-	-	45	103
8	465-00 Mains - INSPECTION	-	14.87%	-	-	-	-	-
9	466-00 Compressor Equipment	-	2.87%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	4.47%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	4.27%	27	-	-	88	115
12	467-20 Telemetering	4	0.31%	-	-	-	(2)	(2)
13	468-00 Communication Structures & Equipment	-	0.00%	-	-	-	-	-
14	TOTAL TRANSMISSION	4,633		85	-	-	126	211
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	3	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	247	3.33%	8	-	-	71	79
20	473-00 Services	2,390	2.29%	55	-	-	805	860
21	474-00 House Regulators & Meter Installations	537	7.44%	40	-	-	194	234
22	477-00 Meters/Regulators Installations	-	0.00%	-	-	-	-	-
23	475-00 Mains	2,107	1.48%	31	-	-	519	550
24	476-00 Compressor Equipment	-	26.54%	-	-	-	(97)	(97)
25	477-00 Measuring & Regulating Equipment	1,119	4.75%	53	-	-	352	405
26	477-00 Telemetering	14	0.25%	-	-	-	12	12
27	478-10 Meters	30	7.89%	2	-	-	4	6
28	478-20 Instruments	-	3.15%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,446		189	-	-	1,860	2,049
31								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	242	4.82%	12	-	-	18	30
6	- Masonry Buildings	343	2.23%	8	-	-	45	53
7	- Leasehold Improvement	-	0.00%	-	-	-	7	7
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	12	6.67%	1	-	-	21	22
10	483-40 GP Furniture	25	5.00%	1	-	-	1	2
11	483-10 GP Computer Hardware	182	20.00%	36	-	-	265	301
12	483-20 GP Computer Software	130	12.50%	16	-	-	23	39
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	11	5.16%	1	-	-	(25)	(24)
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	8.96%	-	-	-	(52)	(52)
18	485-20 Heavy Mobile Equipment	-	18.06%	-	-	-	-	-
19	486-00 Small Tools & Equipment	96	5.00%	5	-	(3)	59	61
20	487-00 Equipment on Customer's Premises	(15)	6.67%	(1)	-	-	(16)	(17)
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	25	6.67%	2	-	-	28	30
24	- Radio	2	6.67%	-	-	-	8	8
25	489-00 Other General Equipment	(2)	0.00%	-	-	-	(2)	(2)
26	TOTAL GENERAL	1,054		81	-	(3)	380	458
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 12,162		$ 355	$ -	$ (3)	$ 2,366	$ 2,718
33								
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 48		- Sect 7-TAB 7.4, Schedule 28			- Sect 7-TAB 7.4, Schedule 40	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	-	1.00%	-	-	-	-	-
4	178-00 Organization Expense	-	1.00%	-	-	-	-	-
5	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
6	401-00 Franchise and Consents	-	49.19%	-	-	-	-	-
7	402-00 Utility Plant Acquisition Adjustment	-	57.14%	-	-	-	-	-
8	402-00 Other Intangible Plant	-	2.38%	-	-	-	-	-
9	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
10	461-00 Transmission Land Rights	9	0.00%	-	-	-	-	-
11	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
12	471-00 Distribution Land Rights	21	0.00%	-	-	-	-	-
13	402-01 Application Software - 12.5%	-	12.50%	-	-	-	-	-
14	402-02 Application Software - 20%	-	20.00%	-	-	-	-	-
15	TOTAL INTANGIBLE	30		-	-	-	-	-

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.74%	-	-	-	-	-
5	463-00 Measuring Structures	-	3.80%	-	-	-	(3)	(3)
6	464-00 Other Structures & Improvements	1	2.83%	-	-	-	(2)	(2)
7	465-00 Mains	4,187	1.44%	60	-	-	103	163
8	465-00 Mains - INSPECTION	-	14.87%	-	-	-	-	-
9	466-00 Compressor Equipment	-	2.87%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	4.47%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	631	4.27%	27	-	-	115	142
12	467-20 Telemetering	4	0.31%	-	-	-	(2)	(2)
13	468-00 Communication Structures & Equipment	-	0.00%	-	-	-	-	-
14	TOTAL TRANSMISSION	4,823		87	-	-	211	298
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	3	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	247	3.33%	8	-	-	79	87
20	473-00 Services	2,490	2.29%	57	-	-	860	917
21	474-00 House Regulators & Meter Installations	542	7.44%	40	-	-	234	274
22	477-00 Meters/Regulators Installations	-	0.00%	-	-	-	-	-
23	475-00 Mains	2,248	1.48%	33	-	-	550	583
24	476-00 Compressor Equipment	-	26.54%	-	-	-	(97)	(97)
25	477-00 Measuring & Regulating Equipment	1,169	4.75%	55	-	-	405	460
26	477-00 Telemetering	14	0.25%	-	-	-	12	12
27	478-10 Meters	34	7.89%	3	-	-	6	9
28	478-20 Instruments	-	3.15%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,746		196	-	-	2,049	2,245
31								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	$ 1	0.00%	$ -	$ -	$ -	$ -	$ -
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	242	4.82%	12	-	-	30	42
6	- Masonry Buildings	407	2.23%	9	-	-	53	62
7	- Leasehold Improvement	-	10.00%	-	-	-	7	7
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	12	6.67%	1	-	-	22	23
10	483-40 GP Furniture	25	5.00%	1	-	-	2	3
11	483-10 GP Computer Hardware	182	20.00%	36	-	-	301	337
12	483-20 GP Computer Software	130	12.50%	16	-	-	39	55
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	11	5.16%	1	-	-	(24)	(23)
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	3	8.96%	-	-	-	(52)	(52)
18	485-20 Heavy Mobile Equipment	-	18.06%	-	-	-	-	-
19	486-00 Small Tools & Equipment	101	5.00%	5	-	(7)	61	59
20	487-00 Equipment on Customer's Premises	(15)	6.67%	(1)	-	-	(17)	(18)
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	25	6.67%	2	-	-	30	32
24	- Radio	2	6.67%	-	-	-	8	8
25	489-00 Other General Equipment	(2)	0.00%	-	-	-	(2)	(2)
26	TOTAL GENERAL	1,124		82	-	(7)	458	533
27								
28	**UNCLASSIFIED PLANT**							
29	499 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 12,722		$ 365	$ -	$ (7)	$ 2,718	$ 3,076
33								
34	Cross Reference	- Sect 7-TAB 7.4, Schedule 51		- Sect 7-TAB 7.4, Schedule 29			- Sect 7-TAB 7.4, Schedule 41	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	$ -	0.18%	$ -	$ -	$ -	$ -	$ -	$ -
3	463-00 Measuring Structures	-	0.18%	-	-	-	-	-	-
4	464-00 Other Structures & Improvements	1	0.14%	-	-	-	-	-	-
5	465-00 Mains	3,997	0.14%	-	-	-	-	-	-
6	466-00 Compressor Equipment	-	0.28%	-	-	-	-	-	-
7	467-10 Measuring & Regulating Equipment	631	0.18%	-	-	-	-	-	-
8	468-00 Communication Structures & Equipment	-	0.00%	-	-	-	-	-	-
9	TOTAL TRANSMISSION	4,633		-	-	-	-	-	-
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	247	0.16%	-	-	-	-	-	-
13	473-00 Services	2,390	1.07%	-	-	-	-	-	-
14	474-00 House Regulators & Meter Installations	537	0.75%	-	-	-	-	-	-
15	475-00 Mains	2,107	0.29%	-	-	-	-	-	-
16	476-00 Compressor Equipment	-	11.43%	-	-	-	-	-	-
17	477-00 Measuring & Regulating Equipment	1,119	0.52%	-	-	-	-	-	-
18	478-10 Meters	30	0.50%	-	-	-	-	-	-
19	TOTAL DISTRIBUTION	6,446		-	-	-	-	-	-
20									
21	TOTALS	$ 12,162		$ -	$ -	$ -	$ -	$ -	$ -
22									
23	Cross Reference	- Sect 7-TAB 7.4, Schedule 48		- Sect 7-TAB 7.4, Schedule 28				- Sect 7-TAB 7.4, Schedule 40	
24									

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Mid-year GPIS for Depreciation	Annual Salvage Rate %	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	462-00 Compressor Structures	$ -	0.18%	$ -	$ -	$ -	$ -	$ -	$ -
3	463-00 Measuring Structures	-	0.18%	-	-	-	-	-	-
4	464-00 Other Structures & Improvements	1	0.14%	-	-	-	-	-	-
5	465-00 Mains	4,187	0.14%	-	-	-	-	-	-
6	466-00 Compressor Equipment	-	0.28%	-	-	-	-	-	-
7	467-10 Measuring & Regulating Equipment	631	0.18%	-	-	-	-	-	-
8	468-00 Communication Structures & Equipment	-	0.00%	-	-	-	-	-	-
9	TOTAL TRANSMISSION	4,823		-	-	-	-	-	-
10									
11	**DISTRIBUTION PLANT**								
12	472-00 Structures & Improvements	247	0.16%	-	-	-	-	-	-
13	473-00 Services	2,490	1.07%	-	-	-	-	-	-
14	474-00 House Regulators & Meter Installations	542	0.75%	-	-	-	-	-	-
15	475-00 Mains	2,248	0.29%	-	-	-	-	-	-
16	476-00 Compressor Equipment	-	11.43%	-	-	-	-	-	-
17	477-00 Measuring & Regulating Equipment	1,169	0.52%	-	-	-	-	-	-
18	478-10 Meters	34	0.50%	-	-	-	-	-	-
19	TOTAL DISTRIBUTION	6,746		-	-	-	-	-	-
20									
21	TOTALS	$ 12,722		$ -	$ -	$ -	$ -	$ -	$ -
22									
23	Cross Reference	- Sect 7-TAB 7.4, Schedule 51		- Sect 7-TAB 7.4, Schedule 29				- Sect 7-TAB 7.4, Schedule 41	
24									

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,287	$ -	$ -	$ -	$ 1,287	
4							
5	Transmission Contributions	-	-	-	-	-	
6							
7	TOTAL Contributions	1,287	-	-	-	1,287	- Sect 7-TAB 7.4, Schedule 39
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(490)	-	-	-	(490)	
14							
15	TOTAL CIAC Amortization	(490)	-	-	-	(490)	- Sect 7-TAB 7.4, Schedule 39
16							
17	**NET CONTRIBUTIONS**	$ 797	$ -	$ -	$ -	$ 797	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 Additions	2012 Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,287	$ -	$ -	$ -	$ 1,287	
4							
5	Transmission Contributions	-	-	-	-	-	
6							
7	TOTAL Contributions	1,287	-	-	-	1,287	- Sect 7-TAB 7.4, Schedule 40
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(490)	-	-	-	(490)	
14							
15	TOTAL CIAC Amortization	(490)	-	-	-	(490)	- Sect 7-TAB 7.4, Schedule 40
16							
17	**NET CONTRIBUTIONS**	$ 797	$ -	$ -	$ -	$ 797	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 Additions	2013 Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,287	$ -	$ -	$ -	$ 1,287	
4							
5	Transmission Contributions	-	-	-	-	-	
6							
7	TOTAL Contributions	1,287	-	-	-	1,287	- Sect 7-TAB 7.4, Schedule 41
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(490)	-	-	-	(490)	
14							
15	TOTAL CIAC Amortization	(490)	-	-	-	(490)	- Sect 7-TAB 7.4, Schedule 41
16							
17	**NET CONTRIBUTIONS**	$ 797	$ -	$ -	$ -	$ 797	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	28	-	(47)	12	(34)	-	(17)	4	(19)	5
3	Interest on CCRA / MCRA / RSAM / Gas Storage	5	-	(1)	-	(1)	-	(2)	1	3	4
4	Gas Cost Reconciliation Account (GCRA)	(45)	-	(16)	4	(12)	-	-	-	(57)	(51)
5											
6	Non-Controllable Items										
7	Property Tax Deferral	(1)	-	(2)	1	(1)	-	-	-	(2)	(2)
8	Interest Variance	(6)	-	(3)	1	(3)	6	-	-	(2)	(4)
9	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
10											
11	Cost of Current Applications										
12	2010-2011 Revenue Requirement Application	21	-	-	-	-	(21)	-	-	-	11
13	2012-2013 Revenue Requirement Application	-	-	5	(1)	4	-	-	-	4	2
14											
15	Other										
16	Deferred Removal Costs	-	-	-	-	-	-	-	-	-	-
17	Gains and Losses on Asset Disposition	-	11	12	-	12	-	-	-	23	17
18	IFRS Transitional Costs	75	-	-	-	-	-	-	-	75	75
19											
20	Residual Deferred Charges										
21	Fort Nelson ROE & Capital Structure Deferral	55	-	-	-	-	(55)	-	-	-	28
22											
23	Total Deferred Charges for Rate Base	$ 132	$ 11	$ (52)	$ 17	$ (35)	$ (70)	$ (19)	$ 5	$ 25	$ 85
24											
25	Cross Reference						- Sect 7-TAB 7.4, Schedule 27			- Sect 7-TAB 7.4, Schedule 39	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	(19)	-	-	-	-	-	8	(2)	(12)	(16)
3	Interest on CCRA / MCRA / RSAM / Gas Storage	3	-	-	-	-	-	(1)	-	2	3
4	Gas Cost Reconciliation Account (GCRA)	(57)	-	76	(19)	57	-	-	-	0	(28)
5											
6	Non-Controllable Items										
7	Property Tax Deferral	(2)	-	-	-	-	1	-	-	(2)	(2)
8	Interest Variance	(2)	-	-	-	-	1	-	-	(1)	(2)
9	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
10											
11	Cost of Current Applications										
12	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
13	2012-2013 Revenue Requirement Application	4	-	-	-	-	(2)	-	-	2	3
14											
15	Other										
16	Deferred Removal Costs	-	-	-	-	-	-	-	-	-	-
17	Gains and Losses on Asset Disposition	23	75	-	-	-	(5)	-	-	93	96
18	IFRS Transitional Costs	75	(75)	-	-	-	-	-	-	-	-
19											
20	Residual Deferred Charges										
21	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
22											
23	Total Deferred Charges for Rate Base	$ 25	$ -	$ 76	$ (19)	$ 57	$ (5)	$ 7	$ (2)	$ 82	$ 54
24											
25	Cross Reference						- Sect 7-TAB 7.4, Schedule 28			- Sect 7-TAB 7.4, Schedule 40	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	(12)	-	-	-	-	-	8	(2)	(6)	(9)
3	Interest on CCRA / MCRA / RSAM / Gas Storage	2	-	-	-	-	-	(1)	-	1	2
4	Gas Cost Reconciliation Account (GCRA)	0	-	-	-	-	-	-	-	0	-
5											
6	Non-Controllable Items										
7	Property Tax Deferral	(2)	-	-	-	-	1	-	-	(1)	(1)
8	Interest Variance	(1)	-	-	-	-	1	-	-	(1)	(1)
9	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
10											
11	Cost of Current Applications										
12	2010-2011 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
13	2012-2013 Revenue Requirement Application	2	-	-	-	-	(2)	-	-	-	1
14											
15	Other										
16	Deferred Removal Costs	-	-	-	-	-	-	-	-	-	-
17	Gains and Losses on Asset Disposition	93	-	-	-	-	(5)	-	-	89	91
18	IFRS Transitional Costs	-	-	-	-	-	-	-	-	-	-
19											
20	Residual Deferred Charges										
21	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
22											
23	Total Deferred Charges for Rate Base	$ 82	$ -	$ -	$ -	$ -	$ (5)	$ 7	$ (2)	$ 82	$ 82
24											
25	Cross Reference						- Sect 7-TAB 7.4, Schedule 29			- Sect 7-TAB 7.4, Schedule 41	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED Existing 2011 Rates	2011 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ (23)	$ 97	$ 52	$ 52	$ (45)	- Sect 7-TAB 7.4, Schedule 75
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(27)	(25)	(16)	(16)	9	
9							
10	Withholdings From Employees	(19)	(18)	(25)	(25)	(7)	
11							
12	Subtotal	(273)	54	11	11	(43)	- Sect 7-TAB 7.4, Schedule 39
13							
14	**Other Working Capital Items**						
15	Gas in Storage	-	-	-	-	-	
16	Inventory - Materials & Supplies	17	3	4	4	1	
17							
18	Subtotal	17	3	4	4	1	- Sect 7-TAB 7.4, Schedule 39
19							
20	Total	$ (256)	$ 57	$ 15	$ 15	$ (42)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	2011 PROJECTED	2012 Existing 2011 Rates	2012 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 52	$ 53	$ 54	$ 2	- Sect 7-TAB 7.4, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(16)	(21)	(21)	(5)	
9						
10	Withholdings From Employees	(25)	(25)	(25)	-	
11						
12	Subtotal	11	7	8	(3)	- Sect 7-TAB 7.4, Schedule 40
13						
14	**Other Working Capital Items**					
15	Gas in Storage	-	-	-	-	
16	Inventory - Materials & Supplies	4	4	4	-	
17						
18	Subtotal	4	4	4	-	- Sect 7-TAB 7.4, Schedule 40
19						
20	Total	$ 15	$ 11	$ 12	$ (3)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 Existing 2011 Rates	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 54	$ 56	$ 59	$ 5	- Sect 7-TAB 7.4, Schedule 75
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(21)	(21)	(21)	-	
9						
10	Withholdings From Employees	(25)	(26)	(26)	(1)	
11						
12	Subtotal	8	9	12	4	- Sect 7-TAB 7.4, Schedule 41
13						
14	**Other Working Capital Items**					
15	Gas in Storage	-	-	-	-	
16	Inventory - Materials & Supplies	4	4	4	-	
17						
18	Subtotal	4	4	4	-	- Sect 7-TAB 7.4, Schedule 41
19						
20	Total	$ 12	$ 13	$ 16	$ 4	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

		2011			2012			2013			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	38.6			38.6			38.6			- Sect 7-TAB 7.4, Schedule 76
4	Expense Lead Days	34.4			34.5			34.4			- Sect 7-TAB 7.4, Schedule 77
5											- Sect 7-TAB 7.4, Schedule 72
6	Net Lead/(Lag) Days	4.2	$ 4,525	$ 52	4.1	$ 4,703	$ 53	4.2	$ 4,857	$ 56	- Sect 7-TAB 7.4, Schedule 73
7											- Sect 7-TAB 7.4, Schedule 74
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	38.6			38.6			38.6			- Sect 7-TAB 7.4, Schedule 76
13	Expense Lead Days	34.4			34.4			34.2			- Sect 7-TAB 7.4, Schedule 77
14											- Sect 7-TAB 7.4, Schedule 72
15	Net Lead/(Lag) Days	4.2	$ 4,525	$ 52	4.2	$ 4,735	$ 54	4.4	$ 4,899	$ 59	- Sect 7-TAB 7.4, Schedule 73
16											- Sect 7-TAB 7.4, Schedule 74
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 1			$ 3	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2011 Revenue At 2011 Rates	2011 Lag Days Service to Collection	2011 Dollar Days	2012 Revenue At 2011 Rates	2012 Lag Days Service to Collection	2012 Dollar Days	2013 Revenue At 2011 Rates	2013 Lag Days Service to Collection	2013 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											
3	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.4, Schedule 14
4	Residential and Commercial	$ 4,563	38.4	$ 175,290	$ 4,633	38.4	$ 177,998	$ 4,705	38.4	$ 180,771	- Sect 7-TAB 7.4, Schedule 16
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	141	45.2	6,382	141	45.2	6,382	141	45.2	6,382	
6	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
7											
8	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	-	0.0	-	-	0.0	-	-	0.0	-	
9											
10	Total Gas Sales	4,704	38.6	181,672	4,774	38.6	184,380	4,846	38.6	187,153	
11	Other Revenues										
12	Royalty Revenue (FEVI)	-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.4, Schedule 4
13	Late Payment Charges	13	38.9	506	13	38.9	506	13	38.9	506	- Sect 7-TAB 7.4, Schedule 18
14	Returned Cheque Charges	-	0.0	4	-	0.0	4	-	0.0	4	- Sect 7-TAB 7.4, Schedule 19
15	Connection Charges	11	37.6	414	11	37.6	414	11	37.6	414	- Sect 7-TAB 7.4, Schedule 20
16	Other Utility Income	-	0.0	-	-	0.0	-	-	0.0	-	
17											
18											
19	Total Revenue	$ 4,728	38.6	$ 182,596	$ 4,798	38.6	$ 185,304	$ 4,870	38.6	$ 188,077	
20											
21											
22	**REVENUE, REVISED RATES**										
23											
24	Gas Sales and Transportation Service Revenue										- Sect 7-TAB 7.4, Schedule 14
25	Residential and Commercial	$ 4,563	38.4	$ 175,290	$ 4,746	38.4	$ 182,342	$ 4,849	38.4	$ 186,306	- Sect 7-TAB 7.4, Schedule 16
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	141	45.2	6,382	150	45.2	6,789	152	45.2	6,879	
27	NGV Fuel - Stations	-	0.0	-	-	0.0	-	-	0.0	-	
28											
29	Rates 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	-	0.0	-	-	0.0	-	-	0.0	-	
30											
31	Total Gas Sales	4,704	38.6	181,672	4,896	38.6	189,131	5,001	38.6	193,185	
32	Other Revenues										
33	Royalty Revenue (FEVI)	-	0.0	-	-	0.0	-	-	0.0	-	
34	Late Payment Charges	13	38.9	506	13	38.9	506	13	38.9	506	- Sect 7-TAB 7.4, Schedule 18
35	Returned Cheque Charges	-	0.0	4	-	0.0	4	-	0.0	4	- Sect 7-TAB 7.4, Schedule 19
36	Connection Charges	11	37.6	414	11	37.6	414	11	37.6	414	- Sect 7-TAB 7.4, Schedule 20
37	Other Utility Income	-	0.0	-	-	0.0	-	-	0.0	-	
38											
39											
40	Total Revenue	$ 4,728	38.6	$ 182,596	$ 4,920	38.6	$ 190,055	$ 5,025	38.6	$ 194,109	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars		2011 Amount	2011 Lead Days Expense to Payment	2011 Dollar Days	2012 Amount	2012 Lead Days Expense to Payment	2012 Dollar Days	2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**											
2												
3	Operating And Maintenance											- Sect 7-TAB 7.4, Schedule 4
4	Expenses		$ 699	25.5	$ 17,825	$ 744	25.5	$ 18,972	$ 771	25.5	$ 19,661	- Sect 7-TAB 7.4, Schedule 5
5	Transportation Costs		-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.4, Schedule 6
6	Gas Purchases (excl Royalty Credits)		2,860	40.2	114,972	2,900	40.2	116,580	2,945	40.2	118,389	
7												
8	Taxes Other Than Income											- Sect 7-TAB 7.4, Schedule 24
9	Property Taxes		168	2.0	336	172	2.0	344	178	2.0	356	- Sect 7-TAB 7.4, Schedule 25
10	Franchise Fees		-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.4, Schedule 26
11	Carbon Tax		636	29.1	18,498	789	29.1	22,946	874	29.1	25,422	
12	HST - Net	*	40	38.8	1,566	98	38.8	3,808	100	38.8	3,868	
13	PST Component of HST (REC)	*	31	37.1	1,148	(26)	33.8	(873)	(26)	33.8	(879)	- Sect 7-TAB 7.4, Schedule 30
14	Income Tax		91	15.2	1,383	26	15.2	395	16	15.2	243	- Sect 7-TAB 7.4, Schedule 31
15												- Sect 7-TAB 7.4, Schedule 32
16	Total		$ 4,525	34.4	$ 155,727	$ 4,703	34.5	$ 162,172	$ 4,857	34.4	$ 167,060	
17												
18												
19	**EXPENSES, REVISED RATES**											
20												
21	Operating And Maintenance											- Sect 7-TAB 7.4, Schedule 4
22	Expenses		$ 699	25.5	$ 17,825	$ 744	25.5	$ 18,972	$ 771	25.5	$ 19,661	- Sect 7-TAB 7.4, Schedule 5
23	Transportation Costs		-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.4, Schedule 6
24	Gas Purchases (excl Royalty Credits)		2,860	40.2	114,972	2,900	40.2	116,580	2,945	40.2	118,389	
25												
26	Taxes Other Than Income											- Sect 7-TAB 7.4, Schedule 24
27	Property Taxes		168	2.0	336	172	2.0	344	178	2.0	356	- Sect 7-TAB 7.4, Schedule 25
28	Franchise Fees		-	0.0	-	-	0.0	-	-	0.0	-	- Sect 7-TAB 7.4, Schedule 26
29	Carbon Tax		636	29.1	18,498	789	29.1	22,946	874	29.1	25,422	
30	HST - Net	*	40	38.8	1,566	101	38.8	3,908	103	38.8	3,994	
31	PST Component of HST (REC)	*	31	37.1	1,148	(27)	33.8	(896)	(27)	33.8	(902)	- Sect 7-TAB 7.4, Schedule 30
32	Income Tax		91	15.2	1,383	56	15.2	851	55	15.2	836	- Sect 7-TAB 7.4, Schedule 31
33												- Sect 7-TAB 7.4, Schedule 32
34	Total		$ 4,525	34.4	$ 155,727	$ 4,735	34.4	$ 162,705	$ 4,899	34.2	$ 167,756	

* 2011 was calculated using prior approved GST and PST method

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2011 TO 2013
($000s)

Line No.	Particulars	2010 ACTUAL	2011 APPROVED	2011 PROJECTED	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Plant & Equipment						
2	Net Book Value *	$ -	$ -	$ -	$ -	$ -	
3	Less: Undepreciated Capital Cost	-	-	-	-	-	
4		-	-	-	-	-	
5	Weighted Average Future Tax Rate	0.00%	0.00%	25.00%	25.00%	25.00%	
6		-	-	-	-	-	
7							
8	Total FIT Liability- After Tax (PP&E)	-	-	-	-	-	
9	Total FIT Liability- After Tax (Non-PP&E)	-	-	-	-	-	
10	Total FIT Liability- After Tax	-	-	-	-	-	
11							
12	Tax Gross Up	-	-	-	-	-	
13							
14	FIT Liability/Asset - End of Year	-	-	-	-	-	
15							
16	FIT Liability/Asset - Opening Balance	-	-	-	-	-	
17							- Sect 7-TAB 7.4, Schedule 39
18	FIT Liability/Asset - Mid Year	$ -	$ -	$ -	$ -	$ -	- Sect 7-TAB 7.4, Schedule 40
19							- Sect 7-TAB 7.4, Schedule 41
20							
21	Note: * FIT Not Applicable for Fort Nelson as it is not it's own legal entity						

($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2011 RATES						
2	Long-Term Debt	$ 3,013	46.92%	6.95%	3.26%	$ 209	- Sect 7-TAB 7.4, Schedule 82
3	Unfunded Debt	840	13.08%	4.50%	0.59%	38	
4	Common Equity	2,569	40.00%	7.58%	3.03%	195	
5							- Sect 7-TAB 7.4, Schedule 4
6		$ 6,422	100.00%		6.88%	$ 442	- Sect 7-TAB 7.4, Schedule 39
7							
8							
9							
10	2011 REVISED RATES - PROJECTED						
11	Long-Term Debt	$ 3,013	46.92%	6.95%	3.26%	$ 209	- Sect 7-TAB 7.4, Schedule 82
12	Unfunded Debt						
13	Adjustment, Revised Rates	840	13.08%	4.50%	0.59%	38	
14	Common Equity	2,569	40.00%	7.58%	3.03%	195	
15							- Sect 7-TAB 7.4, Schedule 4
16		$ 6,422	100.00%		6.88%	$ 442	- Sect 7-TAB 7.4, Schedule 39

($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2012 AT 2011 RATES						
2	Long-Term Debt	$ 5,094	57.31%	6.73%	3.86%	$ 343	- Sect 7-TAB 7.4, Schedule 83
3	Unfunded Debt	239	2.69%	2.75%	0.07%	7	
4	Common Equity	3,555	40.00%	6.95%	2.78%	246	
5							- Sect 7-TAB 7.4, Schedule 5
6		$ 8,888	100.00%		6.71%	$ 596	- Sect 7-TAB 7.4, Schedule 40
7							
8							
9							
10	2012 REVISED RATES						
11	Long-Term Debt	$ 5,094	57.30%	6.73%	3.86%	$ 343	- Sect 7-TAB 7.4, Schedule 83
12	Unfunded Debt						
13	Adjustment, Revised Rates	239	2.70%	2.75%	0.07%	7	
14	Common Equity	3,556	40.00%	9.50%	3.80%	338	
15							- Sect 7-TAB 7.4, Schedule 5
16		$ 8,889	100.00%		7.74%	$ 688	- Sect 7-TAB 7.4, Schedule 40

($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2013 AT 2011 RATES						
2	Long-Term Debt	$ 5,134	56.27%	6.74%	3.79%	$ 346	- Sect 7-TAB 7.4, Schedule 84
3	Unfunded Debt	340	3.73%	3.75%	0.14%	13	
4	Common Equity	3,649	40.00%	6.35%	2.54%	231	
5							- Sect 7-TAB 7.4, Schedule 6
6		$ 9,123	100.00%		6.47%	$ 590	- Sect 7-TAB 7.4, Schedule 41
7							
8							
9							
10	2013 REVISED RATES						
11	Long-Term Debt	$ 5,134	56.25%	6.74%	3.79%	$ 346	- Sect 7-TAB 7.4, Schedule 84
12	Unfunded Debt						
13	Adjustment, Revised Rates	342	3.75%	3.75%	0.14%	13	
14	Common Equity	3,650	40.00%	9.50%	3.80%	347	
15							- Sect 7-TAB 7.4, Schedule 6
16		$ 9,126	100.00%		7.74%	$ 706	- Sect 7-TAB 7.4, Schedule 41

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 69,031 *	12.054%	$ 69,886	$ 8,424
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452
3										
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627
11	2011 Medium Term Debt Issue- Series 25	1-Jul-2011	1-Jul-2021	5.650%	100,000	1,000	99,000	5.783%	50,411	2,915
12										
13										
14	Vehicle Lease Obligation							7.633%	13,455	1,027
15										
16	Sub-Total								$ 1,537,699	$ 106,786
17	Fort Nelson Division Portion of Long Term Debt								3,013	209
18	Total								$ 3,013	$ 209
19										
20	*Includes adjustment of $10,943 for BC Hydro Premium (Series A).							Average Embedded Cost		6.95%
21										
22	Cross Reference								- Sect 7-TAB 7.4, Schedule 79	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 71,908	*	12.054%	$ 72,763	$ 8,771
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	**	10.461%	157,274	16,452
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14											
15	Vehicle Lease Obligation								5.007%	13,782	690
16											
17	Sub-Total									$ 1,587,211	$ 106,891
18	Fort Nelson Division Portion of Long Term Debt									5,094	343
19	Total									$ 5,094	$ 343
20											
21	*Includes adjustment of $13,820 for BC Hydro Premium (Series A).								Average Embedded Cost		6.73%
22	**Includes adjustment of $ for BC Hydro Premium (Series B).										
23	Cross Reference									- Sect 7-TAB 7.4, Schedule 80	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	156,052	**	10.388%	158,280	16,442
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14											
15	Vehicle Lease Obligation								5.630%	13,640	768
16											
17	Sub-Total									$ 1,587,649	$ 107,076
18	Fort Nelson Division Portion of Long Term Debt									5,134	346
19	Total									$ 5,134	$ 346
20											
21	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.74%
22	**Includes adjustment of $1,006 for BC Hydro Premium (Series B).										
23	Cross Reference									- Sect 7-TAB 7.4, Schedule 81	

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 Volumes (TJ)	2013 Volumes (TJ)	2012 Amortization ($000s)	2013 Amortization ($000s)	2012 Amortization o RSAM Unit Rider ($/GJ)	2013 Amortization o RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**RSAM (Rider 5) Calculation**						
2							
3	Schedule 1 - Residential	273.2	274.3			($0.011)	($0.011)
4	Schedule 2.1 - Commercial	203.2	207.8			($0.011)	($0.011)
5	Schedule 2.2 - Commercial	101.0	104.3			($0.011)	($0.011)
7	Schedule 25 - Transportation Service	55.1	55.1			($0.011)	($0.011)
10							
11		632.5	641.5	($7)	($7) [1]		

12
13
14 Note 1: RSAM Rider Change
15
16 In 2011, FortisBC Energy forecasts that there will be approximately $-35 thousand (net-of-tax) of RSAM additions.
17 After offsetting the 2011 RSAM Rider recovery, the RSAM account including interest is now projected to be a
18 credit balance of $-16 thousand on a net-of-tax basis by the end of 2011. The RSAM balance is to be amortized
19 over three years. Accordingly, the net-of-tax RSAM balance to be amortized in each year in 2012 and 2013 is
20 a credit of $-5 thousand. On a pre-tax basis, this amounts to $7 thousand or a refund to the customer of $0.011/GJ
21 in 2012, which is a $0.044 reduction from the existing charge of $0.033/GJ. The corresponding 2013 refund to the
22 customer is $0.011/GJ.
23
24 2012 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2011 RSAM Balance
25 = 1/3 * ($-19 RSAM + $3 RSAM Interest)
26 = 1/3 * $-16
27 = $-5 Net-of-tax amortization
28
29 2012 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
30 = $-5 / (1 - 25%)
31 = $-7 Pre-tax amortization
32
33 2013 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2012 RSAM Balance
34 = 1/2 * ($-12 RSAM + $2 RSAM Interest)
35 = 1/2 * $-10
36 = $-5 Net-of-tax amortization
37
38 2013 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
39 = $-5 / (1 - 25%)
40 = $-7 Pre-tax amortization

8 APPROVALS SOUGHT AND PROPOSED REGULATORY PROCESS

8.1 Approvals Sought

ORDER SOUGHT

The Order Sought has, in general, been broken out by company, but also by year (2012 and 2013). The reason for separating the orders for 2012 and 2013 is because some of the orders will be different in 2013 depending on whether amalgamation proceeds. The 2013 rate orders for each utility are thus conditional, as is the request for a consolidated cost of service.

In this Application, the FortisBC Energy Utilities are respectfully seeking an Order or Orders of the Commission granting the following approvals:

INTERIM 2012 RATES FOR FEI, FEVI, FEW AND FORT NELSON

1. Interim approval, pursuant to section 89 of the Act and section 15 of the *Administrative Tribunals Act,* effective January 1, 2012 of the 2012 rates for FEI, FEVI, FEW and Fort Nelson sought in this Application, as a decision on the permanent rates requested is unlikely to be received in time for implementation effective January 1, 2012, with any variance between interim rates and permanent rates to be refunded to or collected from customers by way of a rate rider following the approval of permanent rates.

2012 RATE APPROVALS FOR FEI

2. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEI for all non-bypass customers effective January 1, 2012, to recover the revenue requirements as described in Section 3.3.1 of the Application, resulting in an increase of 5.0 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

3. Approval of the Rate Stabilization Adjustment Mechanism ("RSAM") rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2U, 2X, 3, 3U, 3X and 23 effective January 1, 2012 of ($0.032)/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the FEI Fourth Quarter 2011 Gas Cost filing.)

4. Approval pursuant to sections 59 to 61 of the Act of the 2012 cost allocation to Thermal Energy Services (formerly Alternative Energy Services) as set out in Section 5.3.18 and Appendix G of the Application.

5. Approval of the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2012 forecast period as set out in Section 5.5 of the Application.

6. Approval of the change in the allocation between the delivery margin and midstream of the SCP costs and revenues, and of the Spectra Energy Kingsvale South charges related to the NWN capacity as set out in Section 5.5 of the Application.

2012 RATE APPROVALS FOR FEVI

7. Approval pursuant to sections 59 to 61 of the Act and section 2.1 of the Vancouver Island Natural Gas Pipeline Agreement Special Direction ("Special Direction") of permanent rates for FEVI effective January 1, 2012 for Core Market sales and transportation customers, other than customers who have specified rates in their transportation service agreements, at the same level as 2011 rates.

8. Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast Cost of Service for 2012 as set out in Section 3.3.2 of the Application.

9. Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast capital expenditures for 2012, as set out in Section 6.2 of the Application.

10. Approval pursuant to section 2.10(a)(ii) of the Special Direction of FEVI's forecast revenue for 2012, based on its proposed rates, as set out in Section 4.5.6 of the Application.

11. Approval of the forecast gross O&M expenditures for 2012 of $35.236 million.

12. Approval of the 2012 cost of gas and discontinuation of the quarterly reporting of gas costs for FEVI as set out in Sections 5.2 and 6.3 of the Application.

13. Approval for the difference between the net revenues received and the actual cost of service, excluding O&M variances from forecast, to be allocated to the RSDA, as set out in Section 3.4.2 of the Application.

2012 RATE APPROVALS FOR FEW

14. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEW for all customers effective January 1, 2012, to recover the requested revenue requirements as described in Section 3.3.3 of the Application, resulting in an increase of 2.2 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

15. Approval of the RSAM rider for customers served under FEW Rate Schedules SGS 1/2, LGS 1, LGS 2 and LGS 3 effective January 1, 2012 of $0.524/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the FEW Fourth Quarter 2011 Gas Cost filing.)

2012 RATE APPROVALS FOR FORT NELSON

16. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for Fort Nelson customers effective January 1, 2012, to recover the requested revenue requirements as described in Section 3.3.4 of the Application, resulting in an increase of 6.5 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge and the minimum monthly service charge.

17. Approval of the RSAM rider for customers served under Fort Nelson Rate Schedules 1, 2.1, 2.2 and 25 effective January 1, 2012 of ($0.011)/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the Fort Nelson Fourth Quarter 2011 Gas Cost filing.)

2013 RATE APPROVALS BY COMPANY, IN EFFECT UNLESS AMALGAMATION AND HARMONIZED RATES ARE PUT IN PLACE

18. The FortisBC Energy Utilities seek the following orders for the implementation of 2013 rates by utility, which will be in effect unless the following occurs: (i) the amalgamation of the FortisBC Energy Utilities proceeds, having obtained the necessary approvals, and (ii) the Commission, in a future proceeding, fixes harmonized rates for the amalgamated entity:

2013 FEI Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(a) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEI for all non-bypass customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.1 of the Application, resulting in an increase of 6.4 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

(b) Approval pursuant to sections 59 to 61 of the Act of the 2013 cost allocation to the Thermal Energy Services (previously referred to as Alternative Energy Services) customer class as set out in Section 5.3.18 and Appendix G of the Application.

(c) Approval to continue debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2013 forecast period as set out in Section 5.5 of the Application.

FEVI 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(d) Approval pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction of permanent rates for FEVI effective January 1, 2013 for Core Market sales and transportation customers, other than customers who have specified rates in their transportation service agreements, at the same level as 2011 rates.

(e) Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast Cost of Service for 2013 as set out in Section 3.3.2 of the Application.

(f) Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast capital expenditures for 2013, as set out in Section 6.2 of the Application.

(g) Approval pursuant to section 2.10(a)(ii) of the Special Direction of FEVI's forecast revenue for 2013, based on its proposed rates, as set out in Section 4.5.6 of the Application.

(h) Approval of the forecast gross O&M expenditures for 2013 of $35.482 million.

(i) Approval of the 2013 cost of gas as set out in Section 5.2 of the Application;

(j) Approval for the difference between the net revenues received and the actual cost of service, excluding O&M variances from forecast, to be allocated to the RSDA, as set out in Section 3.4.2 of the Application.

FEW 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(k) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEW for all customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.3 of the Application, resulting in an increase of 11.9 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

Fort Nelson 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(l) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for Fort Nelson customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.4 of the Application, resulting in an increase of 1.6 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge and the minimum monthly service charge.

COMBINED COST OF SERVICE AND OTHER ORDERS IN ANTICIPATION OF APPLICATION FOR AMALGAMATION AND HARMONIZED RATES

19. Determination of an amalgamated cost of service for 2013 for FEI, FEVI, FEW and Fort Nelson combined as set out in Section 3.3.5 of the Application, in anticipation of an Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011. The determination of the amalgamated cost of service does not in any way pre-determine the merits of any future application by the FEU to address amalgamation and harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

20. Approval of a deferral account to capture the costs and savings related to the amalgamation that vary from the forecast of zero for 2013. The approval of this deferral account does not in any way pre-determine the merits of any future application by the FEU to address amalgamation and harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

21. Approval to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09, to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011 as described in Section 5.7 of the Application.

ANCILLARY RATE APPROVALS FOR FEI, FEVI, FEW AND FORT NELSON

22. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and each of FEI, FEVI and FEW, as reflected in the Corporate Services Agreements between FortisBC Energy Holdings Inc. and FEI, FEVI and FEW as described in Section 5.3.18 of the Application.

23. Approval of the allocation of costs for shared services between FEI and FEVI, as described in Section 5.3.18 of the Application.

24. Approval of the allocation of costs for shared services between FEI and FEW, as described in Section 5.3.18 of the Application.

25. Approval to allow for charges between regulated entities to be based on a fully loaded benefits and concessions charge and to not include overheads, including a facilities fee as described in Section 5.3.18 of the Application.

26. Approval of the consolidated Core Market Administration Expense (for FEI, FEVI and FEW), and allocation percentages, as set out in Section 5.2 of the Application.

27. Approval of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI, FEVI, FEW and

Fort Nelson all as set out in Section 6.2 and Appendix G of the Application and summarized in the following table.

Type of Change	Account	Company	Reference
New Account	Compliance to Emission Regulations	FEU	Section 6.3.2.3; Additions and Amortization period TBD
	Customer Service Variance Account	FEU	Section 6.3.3.10; Additions and Amortization period TBD
	Vancouver Island Joint Venture Litigation Costs	FEVI	Section 6.3.3.11; amortization period of 1 year commencing January 1, 2012
	2012-2013 Revenue Requirement Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2012, allocated to FEU based on average customers
	Long Term Resource Plan Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2013, allocated to FEU based on average customers
	Gas Assets Records Management Project	FEU	Section 6.3.5.11; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	BCOneCall Project	FEU	Section 6.3.5.12; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	Residual Delivery Rate Riders	FEI	Section 6.3.6.3; amortization period of 1 year commencing January 1, 2012
Amortization Period Change- New or Modified	Revenue Stabilization Account Mechanism	FEW	Section 6.3.1.3; recovery through Rate Rider 5, 3 year recovery period consistent with FEI and FN, commencing January 1, 2012
	Gas in Storage Interest	FEI	Section 6.3.1.4; 3 year amortization period, commencing January 1, 2012
	Property Tax Variance Account	FEW, FN	Section 6.3.3.1; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Tax Variance Account	FEW	Section 6.3.3.6; 1 year amortization period, commencing January 1, 2012
	Vancouver Island HST Implementation	FEVI	Section 6.3.3.7; 1 year amortization period, commencing January 1, 2012
	Victoria Regional Centre CPCN	FEVI	Section 6.3.4.3; 1 year amortization period, commencing January 1, 2012
	Pipeline Contributions Variance Account	FEW	Section 6.3.5.3; 1 year amortization period, commencing January 1, 2012

Type of Change	Account	Company	Reference
	Deferred Removal Costs	FEU	Section 6.3.5.5; 2 year amortization period, commencing January 1, 2012
	IFRS Transitional Account	FEI, FEVI	Section 6.3.5.7; amortization by plan over EARSL
	2010-2011 Customer Service O&M and Cost of Service	FEU	Section 6.3.5.9; 8 year amortization period, commencing January 1, 2012
Other	Energy Efficiency and Conservation	FEU	Section 6.3.2.1; 4. Combined EEC rate base deferral account additions of $20.0 million in 2012 and $20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period; 5. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis; 6. The creation of the EEC Incentive non-rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.
	CNG and LNG Service Costs and Recoveries	FEI	Section 6.3.2.6; inclusion of variations from the revenue forecast pertaining to Rate Schedule 16
	Property Tax Variance Account	FEW	Section 6.3.3.1; include the forecast balance of the existing Propane Plant Property Tax Deferral account in the Property Tax Variance account
	Tax Variance Account	FEI	Section 6.3.3.6; inclusion of LILO reassessment costs
	Gains and Losses on Asset Disposition	FEU	Section 6.3.5.6; transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on Asset Disposition account; 20 year amortization period, commencing January 1, 2012
Discontinuance	Residential Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012
	Commercial Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012

28. Approvals pursuant to sections 59-61 of the Act of changes to the following accounting policies to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012:

    (a) The depreciation and amortization rates and the creation of a separate sub account (474.02) to record future additions to Distribution Systems Meters/Regulator Installations with depreciation expense for this sub account calculated using a whole life rate, set out in Sections 5.4.2 and 5.4.5 of the Application.

    (b) The negative salvage rates and the treatment of negative salvage as set out in Section 5.4.3 of the Application.

    (c) Modification to the approved Lead Lag days with the removal of the GST and PST lead days and the insertion of the proposed HST and REC lead days as set out in Section 6.1 of the Application.

ENERGY EFFICIENCY AND CONSERVATION ORDERS FOR 2012 AND 2013

29. Acceptance pursuant to section 44.2 of the Act of the EEC expenditures of up to $74.5 million for FEU in 2012 and 2013, with expansion of all EEC program eligibility to customers of FEW and to offer the interruptible industrial program area to customers of FEVI, all as set out in Appendix K-1 of the Application. For clarity, the overall funding level of $74.5 million may not be exceeded and, while the Companies may only spend those funds on approved Program Areas (e.g.: Residential, Commercial, and Innovative Technologies), the Companies may transfer funds between approved program areas and will report on funding transfers in their EEC Annual Report. Treatment of EEC costs will be in accordance with the EEC deferral accounts set out above.

30. With respect to the assessment of EEC expenditures, as described in Appendix K-1 of the Application:

    (a) Approval to continue evaluating EEC expenditures as an overall portfolio, and with Innovative Technologies having an additional criterion that as an individual program area it must have a benefit-cost ratio of 1.0 or greater, as previously approved in the 2010-2011 RRA;

    (b) Approval to continue evaluating EEC expenditures on the basis previously approved by the Commission, except with respect to the following changes.

        (i) The overall portfolio including all EEC-funded activity, and the Innovative Technology program area individually, should have a benefit-cost result of 1.0 or greater, using a Societal Cost Test consisting of the following three modifications to the current benefit-cost analysis:

(A) Use of a social discount rate of 3 percent, rather than the Companies' weighted average cost of capital;

(B) Use of the ceiling price for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas;

(C) Use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity.

(ii) The inclusion of spillover in the calculation of the Net-to-Gross Ratio when estimating program effects.

(c) The evaluation of EEC programs will continue to take place in the context of the EEC Annual Report to be filed by the FEU.

8.2 Proposed Regulatory Process

The FEU propose that this Application can be addressed efficiently and effectively through a Negotiated Settlement Process ("NSP"), or in the alternative, by a written hearing process. ,

The FEU propose the following draft regulatory timetable which acknowledges the workload required by the Commission and all parties and which will promote an efficient regulatory process.

ACTION	DATE (2011)
Workshop (commencing at 1:00 pm)	Wednesday, May 18
Procedural Conference (Timetable and Process - commencing at 9:00 am)	Tuesday, May 24
Procedural Order	Thursday, May 26
Commission Information Request No. 1 to FEU	Thursday, June 2
Intervener Information Request No. 1 to FEU	Thursday, June 9
FEU Response to Information Requests No. 1	Thursday, June 30
Commission Information Request No. 2 to FEU	Thursday, July 21
Intervener Information Request No. 2 to FEU	Thursday, July 21
FEU Response to Information Requests No. 2	Friday, August 19
Negotiated Settlement Process or Hearing if Required (proposed date range)	Tuesday, September 6 to Friday, September 30
FEU Final Argument Submissions	Friday, October 7

ACTION	DATE (2011)
Intervener Final Argument Submissions	Friday, October 21
FEU Reply Argument Submissions	Friday, November 4
Workshop (commencing at 1:00 pm)	Wednesday, May 18

At the procedural conference contemplated in the above timetable, the Companies will address matters including the following:

1. The rationale for requesting an NSP, or alternatively a written hearing process.
2. The request for interim rates effective January 1, 2012, pursuant to section 89 of the UCA and section 15 of the *Administrative Tribunals Act*. The rationale for the request for interim rates is that, based on the proposed schedule, the timing of a Commission Decision on this Application would be well into 2012. The contemplated process would not be possible without having interim rates in place because not having interim rates in effect January 1, 2012 precludes recovery of the cost of service between January 1, 2012 and the implementation date of the permanent rates. Interim rates thus allow the Commission and interveners to consider this Application within a reasonable time frame, without having to unduly hasten the process to facilitate a Commission determination prior to January 1, 2012.

   In terms of whether the interim rates should reflect the current rates or the proposed rates, the FEU are seeking interim approval of the proposed 2012 rates for FEI, FEVI, FEW and Fort Nelson. This request is fair to the Company and customers and is warranted on the basis of the evidence filed. Any variance between interim rates and permanent rates would be refunded to or collected from customers by way of a rate rider following the approval of permanent rates, as contemplated in the Orders Sought.

3. The Companies' request for approval to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09 to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011 as described in Section 5.7 of the Application.

The FEU are optimistic that the Commission will be in a position to make its determination regarding the type of hearing process and the other matters following the procedural conference proposed for May 24, 2011.

The FEU look forward to working with the Commission and Interveners towards an efficient review of this Application.

Appendix A

GLOSSARY

APPENDIX A – GLOSSARY OF TERMS

AAM – Adjustment Mechanism

ABSU – Accenture Utilities Business Process Outsourcing Services

ACESA – American Clean Energy Security Act

ACP – Annual Contracting Plans, which are yearly filings with the Commission providing details on the Company's gas supply and midstream resource procurement activities for the year and discussion of the factors and influences affecting gas supply costs in the short and longer term.

Act – Utilities Commission Act

AES – formerly Alternative Energy Services, see "Thermal Energy Services"

AFUDC – Allowance for Funds Used During Construction, which is an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost.

AFUE – Annual Fuel Utilization Efficiency

AGS – FEVI Apartment General Service Rate Class (serve the common energy requirements of six or more residential units)

AHRI – Air-Conditioning, Heating, and Refrigeration Institute

AIMP – Asset Integrity Management Plan

AIT – Agreement on Internal Trade

AKBLG – Association of Kootenay Boundary Local Government

AM/FM – Automated Mapping/Facilities Management system

AMR – Automated Meter Reading

AMS – Application Management Services

ANSI – American National Standards Institute

APEGBC – Association of Professional Engineers and Geoscientists of BC

API – American Petroleum Institute

Application – FortisBC Energy Utilities 2012-2014 Revenue Requirements Application

ARO – Asset Retirement Obligation

ASL – Average Service Life

ASTTBC – Applied Science Technologists and Technicians of British Columbia, or Association for Technology Professionals in British Columbia

AUBPOS – Accenture Utilities BPO Services

AVICC – Association of Vancouver Island and Coastal Communities

BC or B.C. – British Columbia

BCAOMA – British Columbia Apartment Owners & Managers Association

BCBC – Business Council of British Columbia

BCHL – BC Hockey League

BC Hydro – British Columbia Hydro and Power Authority

BCIT – British Columbia Institute of Technology

BCSA – British Columbia Safety Authority

BCSEA – British Columbia Sustainable Energy Association

BCUC – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Biomethane (Biogas) - a gas substantially composed of methane that is produced by the breakdown of organic matter (biomass) in the absence of oxygen. This breakdown process is also known as anaerobic decomposition. One of the primary products of anaerobic decomposition is gaseous methane, which is also the primary component of natural gas.

BOC – Bank of Canada

BPO – Business Process Outsource

BSI – British Standards Institute

BTU – British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit

BVA – Biomethane Variance Account

CAFÉ – Customer Attraction Front End project

Capex – Capital expenditures

CAT – Climate Action Team

CBOC – Conference Board of Canada

CCA – Capital Cost Allowance

CCE – Customer Care Enhancement Project

CCE – Consortium for Energy Efficiency (EEC 2010 Report)

CCRA – Commodity Cost Reconciliation Account

CEA – Clean Energy Act (Bill 17 – 2010)

CEC – Commercial Energy Consumers Association of British Columbia

CEO – Conservation Education and Outreach

CEPA - Canadian Energy Pipeline Association

CFA – Compressor Facilities Agreement

CGA – Canadian Gas Association

CHBA – Canadian Home Builders' Association

CHF – Co-operative Housing Federation

CIAC – Contributions in Aid of Construction, which is composed of opening contributions plus additions, less retirements.

CICA – Canadian Institute of Chartered Accountants

CIPH – Canadian Institute of Plumbing and Heating

CIS – Customer Information System

ClickSchedule – a Distribution field resources work scheduling platform

CMAE - Core Market Administration Expense, which are costs resulting from the management activities performed within the Gas Supply area to serve core market customers and are treated as a flow-through cost to core market customers as part of gas costs.

CMHC – Canada Mortgage and Housing Corporation

CNG – Compressed Natural Gas, which refers to CNG Service for Natural Gas Vehicles.

COC – Code of Conduct, which is a policy document approved by the Commission setting out the working relationships between Terasen Gas Inc. and non-regulated affiliates

COG – Cost of Gas

Cogeneration – refers to the simultaneous generation of electricity and useful thermal energy by utilizing the waste heat from a gas turbine to generate steam to be used in another process.

Commission - British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Company – FortisBC Energy Inc. or FEI

Compression / Compressor Station – the application of increased pressure to a natural gas pipeline system to create gas flow. Higher levels of compression can be applied to increase the carrying and storage capacity of the pipeline. Increased pressure is applied through a compressor station constructed along the pipeline.

COPE – Canadian Office of Professional Employees

COR – Certificate of Recognition by WorkSafeBC

Core / Core Customers / Core Market – residential, commercial and small industrial customers that have gas delivered to their home or business (bundled sales). Terasen Gas purchases natural gas and delivers it to the customer in a bundled sales rate. Core Market customers typically use a significant portion of their gas requirements for heating applications, resulting in weather sensitive demand.

COS – Cost of Service, a term used in utility ratemaking referring to the total costs of providing a service, typically including operating expenses, depreciation expense, taxes and a fair return on investment for the utility. In some cases Cost of Service also includes cost of gas

COSA – Cost of Service Analysis

COV – City of Vancouver

CP – Cathodic Protection

CPCN – Certificate of Public Convenience and Necessity, a certificate is obtained from the BCUC under Section 45 of the Utilities Commission Act for the construction and, or operation of, a public utility plant or system, or an extension of either, that is required for public convenience and necessity.

CPI – Consumer Price Index

CPR - Conservation Potential Review, a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

CRA – Canada Revenue Agency

CS – Compression Service

CS – Customer Service Department

CSA – Canadian Standards Association

CST – California Standard Tests

CWHI - Condensing Water Heater Initiative

CWLP – CustomerWorks Limited Partnership

DA – Distribution Apprentice

DC – Pacific Resource Conservation Society's Destination Conservation program

DCRS – Digitized Construction Records System

Deferred Costs (or Charges) – operating and maintenance costs that are incurred but that will be expensed in the future.

Demand Forecast – a prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions. Separate demand forecasts are developed for annual energy demand and peak day demand and utilized for different aspects of utility operations and planning.

DES – District Energy Systems

DHW – Domestic Hot Water

DLE – Diesel Litre Equivalent,

DP – Distribution Pressure, pipelines operating at pressures of 100 psig or less (700 kPa or less)

DMS – Distribution Mobile Solution

DR – Disaster Recovery

DRP – Disaster Recovery Plan

DSM – Demand-Side Management, defined as "any utility activity that modifies or influences the way in which customers utilize energy services". From Terasen Gas' perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

DSMS – Demand Side Management System

EARSL – Expected Average Remaining Service Life

ECAP – Energy Conservation Assistance Program

ECM – Electronically Commutated Motors

EEC – Energy Efficiency and Conservation.

EEC Application – 2008 Energy Efficiency and Conservation Programs Application

EEC Decision – BCUC Order No. G-36-09

EF – Efficiency Factor

EH&S – Environment, Health & Safety

ELG – Equal Life Group

ELT – Executive Leadership Team

EMA – Environmental Management Act

EMP – Environmental Management Plan

EMS – Energy Management Services

ERM – Enterprise Risk Management

ESK – Energy Saving Kit

ESM – Earnings Sharing Mechanism

ES&ER – Energy Solutions and External Relations

ES&RD – Energy Supply & Resource Development

ESS/MSS – Employee Self Serve and Manager Self Serve

FBU – The Fortis BC Utilities (comprised of FortisBC Inc. and the FortisBC Energy Utilities [including FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.])

FE – Fireplace Efficiency

FEED – Front End Engineering and Design

FEI – FortisBC Energy Inc. (formerly Terasen Gas Inc.)

FEVI – FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.)

FEW – FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.)

FERC – Federal Energy Regulatory Commission

Fort Nelson – FortisBC Energy Inc. – Fort Nelson Service Area (formerly Terasen Gas Inc. – Fort Nelson Service Area)

FEU – FortisBC Energy Utilities (comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (formerly Terasen Gas Utilities)

FHI – FortisBC Holdings Inc. (formerly Terasen Inc.)

Fraser Basin – Fraser Basin Council

Free Rider Rate – percent who would have implemented an energy efficiency measure even without the program.

FT – FEVI Firm Transportation Service Rate Class

FTE – Full time equivalent employee

GAAP – Generally Accepted Accounting Principles

GCRA – Gas Cost Reconciliation Account

GCVA – Gas Cost Variance Account

GDP – Gross Domestic Product

GGRTA – Greenhouse Gas Reduction Targets Act

GHG – Greenhouse Gas

GHSP – Ground Source Heat Pump

GI – Ground Improvement barriers, used in geotechnical remediation.

GIS – Geographic Information Systems

GJ or Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GLE – Gasoline Litre Equivalent

GPIS – Gross Plant In-Service ending balances consist of opening GPIS plus plant additions, both regular and CPCNs, less retirements.

GSMIP – Gas Supply Mitigation Incentive Plan

GSHP – Ground Source Heat Pump

GST – Goods and Services Tax (replaced by the Harmonized Sales Tax)

GT&C – General Terms and Conditions

GWh – Gigawatt-hours

HDD – Heating Degree Day, which is a measurement designed to reflect the demand for energy needed to heat a home or business, and derived from measurements of outside air temperature.

HEX Pilot – Heat Exchanger Pilot Program

HLF – FEVI Large Commercial Service Rate High Load Factor (consumption 6,000 GJ per year or greater, contract for service, monthly coincident peak load factor greater than 85%)

HPBAC – Hearth, Patio & Barbecue Association of Canada

HR – Human Resources

HRIS – Human Resources Information System

HST – Harmonized Sales Tax

HVAC – Heating, Ventilation, and Air Conditioning

IAS – Internal Audit Services

IASB – International Accounting Standards Board

IBEW – International Brotherhood of Electrical Workers

ICE Fund – Innovative Clean Energy Fund

ICE Levy – Innovative Clean Energy levy of 0.4% on purchases of energy including electricity and natural gas was eliminated effective July 1, 2010.

ICP – Island Cogeneration Plant

IFRS – International Financial Reporting Standards

ILF – Inverse Load Factor - FEVI Large Commercial Service Rate Inverse Load Factor (seasonal use, contract for service)

ILI – In-line inspection

IMP – Integrity Management Plan

IP – Intermediate pressure

IPPs – Independent Power Producers

IRs – Information Requests

IRM – Integrated Resource Management

ISO – International Organization for Standardization

IT – Information Technology

IT (related to rate classes) – FEVI Interruptible Service Rate Class

ITC – Input Tax Credit

ITI – Infrastructure Management

ITS – Interior Transmission System

IVR – Interactive Voice Response

JPS – Jackson Prairie Storage

JV – Joint Venture

KMI – Kinder Morgan Inc.

LCS – Large Commercial Service Rate Class

LCS-1 – FEVI Large Commercial Service Rate Class (consumption 600 GJ per year or greater)

LCS-2 – FEVI Large Commercial Service Rate Class (consumption 2,000 GJ per year or greater)

LCS-3 – FEVI Large Commercial Service Rate Class (consumption 6,000 GJ per year or greater)

LCS-13 – FEVI Large Commercial Service Rate Class – Transport Service (consumption 6,000 GJ per year or greater, sign contract for service, daily energy metering required, customer to supply own gas)

LCT – Large Corporations Tax

LDC – Local Distribution Company

LEAP – LiveSmart BC Energy Assistance Program

LGIC – Lieutenant Governor in Council

LGMA - Local Government Management Association

LGS – Large General Service Rate Schedule

LILO – Lease In-Lease Out

LiveSmart BC – LiveSmart BC Efficiency Incentive Program

LMLGA – Lower Mainland Local Government Association

LMS – Learning Management System

LNG – Liquefied natural gas, natural gas stored at a low temperature turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.

LNG Facility – Mt. Hayes LNG Storage Facility

LP – Low Pressure

LTAP – Long Term Acquisition Plan

LTRP – Long Term Resource Plan

LTSP – Long Term Sustainment Plan, which includes enhancements to the Companies' asset management and system integrity processes.

M&E – Management and Exempt employees

MBH – 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

Mainland – FortisBC Energy Inc. service region (encompasses Lower Mainland, Columbia and Interior)

MCRA – Midstream Cost Reconciliation Account

MEM – Ministry of Energy and Mines

MFD – Multi Family Dwelling

MFT – Motor Fuel Tax of 1.9 cents per 810.32 litres of natural gas used in compressors.

MIT – Manager-in-Training

MMcfd – One Million Cubic Feet per Day

MOU – Memorandum of Understanding

Mt – Megatonne

MTBO – mean time between overhauls

MTN – Medium Term Note

MURB – Multi-Unit Residential Buildings

MVHC – Metro Vancouver Housing Corporation

MX Test – Main Extension economic test analyzes cost estimates for installing a gas main, projections in numbers of customers attached as well as forecast customer gas usage.

MW – Megawatt

NCMA – Northern Community Municipal Association

NEB – National Energy Board

NGT – Natural Gas Transportation, which refers to the NGV initiatives within the Innovative Technologies Program Area.

NGTL – Nova Gas Transmission Limited

NGV – Natural Gas for Vehicles

NPIS – Net Plant in Service is the sum of the averages of the gross plant in-service, CIAC, accumulated depreciation, and negative salvage.

NPV – Net Present Value

NRB – Non-regulated Business

NRCan – Natural Resources Canada

NSA – Negotiated Settlement Agreement

NSP – Negotiated Settlement Process

NSF – Not Sufficient Funds

NWGA – Northwest Gas Association

NWN – Northwest Natural Gas Company

NWP – Northwest Pipeline Corporation

OEM – Other Equipment Manufacture

OGC – British Columbia Oil and Gas Commission

OGAA – British Columbia Oil and Gas Activities Act

OPEB – Other Post Employment Benefits

O&M or Operating and Maintenance Costs - all costs incurred to operate and maintain the completed Customer Care Enhancement Project and that do not result in an improvement of a long-term asset; these costs will be included in regular operating budgets and treated as an operating and maintenance expense.

OSC – Ontario Securities Commission

OSR – Operations Support Representatives

Participant Test – is the measure of the quantifiable benefits and costs to the customer due to participation in a program.

PBR – Performance Based Rates

PBR Agreement – FortisBC Energy Inc's former PBR Agreements covering the periods of 2004-2009 approved pursuant Order No. G-51-03 and extended pursuant to Order No. G-33-07

PCBs – Polychlorinated Biphenyls

PCEC – Pacific Coast Energy Corporation

PCEPA – Pacific Coast Energy Pipeline Agreement revolving credit facility, which matures in January 2013.

PCT – Pacific Carbon Trust

PI – Profitability Index

PJ – Petajoule – equal to 1000 terajoules or 10^6 gigajoules.

PLE – Propane Litre Equivalent

PMO – Project Management Office (Terasen Gas department)

PNG – Pacific Northern Gas

PPE – Property, Plant and Equipment

PPM – Project Portfolio Management

PRMP – Price Risk Management Plan

PST – Provincial Sales Tax in British Columbia

PV – Present Value

QDP – Qualified Dealers Program

QUEST - Quality Urban Energy Systems of Tomorrow

RACOG – Royalty Adjusted Cost of Gas

Rate Volatility – the magnitude and frequency of natural gas rate fluctuations

RDA – Rate Design Application

RDDA – Revenue Deficiency Deferral Account

REC – Residential Energy Credit

REnEW – Residential Energy and Efficiency Works

REUS – Residential End Use Survey

RFEOI – Request for Expressions of Interest

RGS – FEVI Residential General Service Rate Class

RIB – Residential Inclining Block

RIM or Rate Impact Measure – a test that measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

RLCFRR – Renewable and Low Carbon Fuel Requirements Regulation

RMDM – Retail Markets Downstream of the Meter

ROE – Return on Equity

ROW – Right of Way

RRA – Revenue Requirements Application

RRSP – Registered Retirement Savings Plan

RSAM – Revenue Stabilization Adjustment Mechanism

RSDA – Rate Stabilization Deferral Account

RR Settlement Agreement – FEVI's Revenue Requirements Settlement Agreement approved pursuant Order No. G-126-05 and extended pursuant to Order No. G-33-07

RR Settlement Period – Four year period of FEVI's PBR Agreement commencing January 1, 2006 ending December 31, 2009

SAP – System, Applications and Products

SCADA – Supervisory Control and Data Acquisition

SCC – Stress Corrosion Cracking

Scorecard – a strategic performance management tool containing business performance metrics which include a mixture of financial and non-financial measures each compared to a 'target' value

SCP – Southern Crossing Pipeline

SCS – Small Commercial Service Rate Class

SCS-1 – FEVI Small Commercial Service Rate Class (consumption less than 200 GJ per year)

SCS-2 – FEVI Small Commercial Service Rate Class (consumption 200 GJ per year or greater)

SDE – Service Delivery Enhancement Project

SEMP – Strategic Energy Management Plan

SENC – Super Efficient New Construction

SERP – Supplemental Executive Retirement Plan

SFU – Simon Fraser University

SGS – FEW General Service Rate Class

SHIFT – Sustainability and Social Responsibility Attitudes Study

SIA – Service Information Application, used to store the alpha numeric service data to produce gas service lists and provide general gas service information.

SILGA – Southern Interior Local Government Association

SLCA – Service Line Cost Allowance

SMI – Smart Metering Initiative (BC Hydro)

SPIFF – Sales Promotion Incentive Fund

SQI – Service Quality Indicator

SST – Social Services Tax

ST&Cs – Standard Terms and Conditions (Tariff)

Task Force – Affordable Energy Conservation Task Force

TCPL – TransCanada Pipelines Limited

TDGA – Transportation of Dangerous Goods Act

TEEC – Technology Education and Career Council

Terasen or Terasen Inc. – the former name for FortisBC Holdings Inc., a wholly owned subsidiary of Fortis Inc., parent company to the FortisBC Energy Utilities

Terasen Utilities – the former name of the FortisBC Energy Utilities comprised of FEI, FEVI and FEW (formerly comprised of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.)

TES or Terasen Energy Services Inc. – the former name for FortisBC Alternative Energy Services Inc.

TGI or Terasen Gas Inc. – the former name for ,FortisBC Energy Inc. or FEI

TGVI or Terasen Gas (Vancouver Island) Inc. – the former name for FortisBC Energy (Vancouver Island) Inc. or FEVI

TGW or Terasen Gas (Whistler) Inc. – the former name FortisBC Energy (Whistler) Inc. or FEW

Thermal Energy Services – formerly referred to as Alternative Energy Services ("AES") programs and activities

TILMA – Trade, Investment and Labour Mobility Agreement

TJ – Terajoule – equal to 1000 gigajoules.

TRC – Total Resource Cost test, which that measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

Total Rewards – all of the tools available to an employer that may be used to attract, motivate and retain employees. Total Rewards includes everything the employee perceives to be of value resulting from the employment relationship.

TPIP – Transmission Pipeline Integrity Program

TPP – Transfer Pricing Policy

TSA – Transportation Services Agreement

UAF – Unaccounted-for Gas, which refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use.

UBC – University of British Columbia

UBCM - Union of British Columbia Municipalities

UCA – Utilities Commission Act

UCC – Undepreciated Capital Cost

UFV – University of the Fraser Valley

UOC – Utilities Operating Committee

UPC – Use per Customer

USP - Utilities Strategy Project

Utility Cost Test – measures the net costs of demand-side management programs as a resource option based on the costs incurred by the utility (including incentive costs) and exclude the net costs incurred by the participant.

VIGJV – Vancouver Island Gas Joint Venture

VINGPA – Vancouver Island Natural Gas Pipeline Agreement

WACC – Weighted Average Cost of Capital

WACOG – Weighted Average Cost of Gas

WCI – Western Climate Initiative

WEI – Western Energy Institute

Westcoast – Westcoast Energy Inc.

WHIMIS - Workplace Hazardous Materials Information System

WIP – Work in Progress

WM – Waste Management of Canada Corporation

WMS/PM – Work Management System/Preventive Maintenance

WWTP – Waste Water Treatment Plant

Appendix B-1

COMPANY HISTORY

CORPORATE HISTORY

1 FORTISBC ENERGY INC.

1.1 Overview

The FortisBC Energy Inc. ("FEI")[1] is a company incorporated under the laws of the Province of British Columbia ("BC" or "Province") with almost 60 years of history in the natural gas business offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

The company began distribution and transmission of natural gas in BC in the 1950's. In 1952, Inland Natural Gas Co. Ltd. ("Inland") was incorporated to distribute natural gas throughout the BC interior. In the 1950's, Inland purchased several subsidiaries, including St. John Oil and Gas, Peace River Transmission, Canadian Northern Oil and Gas, and Grand Prairie Transmission. In 1977, Inland purchased Columbia Natural Gas in the East Kootenays, which positioned Inland as the major distributor of natural gas for most of the BC Interior. In 1985 Inland acquired Fort Nelson Gas Ltd., the owner of the gas distribution system in and around Fort Nelson, from Colonial Oil and Gas Limited and in 1987, Inland purchased Squamish Gas Co. Ltd. from Superior Propane Ltd. In 1988, through a holding company named B.C. Gas Inc., Inland purchased the Lower Mainland gas division of British Columbia Hydro and Power Authority. In 1989, Inland was amalgamated with BC Gas Inc., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. under the name BC Gas Inc. and become the fourth largest gas distribution utility in Canada.

In 1990, BC Gas commenced construction, operation and maintenance of a piped propane distribution system to serve residential and commercial customers in Revelstoke. Propane is transported to Revelstoke by railcar and tanker-truck and off-loaded at an above-ground site. The propane is vapourized at the above-ground site and then distributed through underground gas lines, today serving approximately 1,600 residential and commercial customers.

In 1993 restructuring caused BC Gas Inc. to change its name to BC Gas Utility Ltd. and a holding company that held all the shares of BC Gas Utility Ltd. was named BC Gas Inc. A subsidiary of BC Gas Utility Ltd. was Squamish Gas Co. Ltd. BC Gas Inc. purchased Centra Gas BC Inc. and Centra Gas Whistler Inc. in 2002, adding natural gas customers on the Sunshine Coast and Vancouver Island and piped propane customers in Whistler. In 2003, BC Gas Inc. changed the name of each of its corporate entities, with BC Gas Inc. becoming Terasen Inc. (the holding company of the natural gas utilities) and BC Gas Utility Ltd. becoming Terasen Gas Inc.

In 2005, Terasen Inc. (the holding company of the natural gas utilities) was acquired by Kinder Morgan Inc., a U.S. energy storage and transportation company operating on behalf of Kinder

[1] Formerly Terasen Gas Inc.

Morgan Energy Partners, L.P. In 2007, Terasen Gas Inc. and Terasen Gas (Squamish) Inc. were amalgamated to operate as one company under the name, Terasen Gas Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc., and on March 1, 2011, the Terasen group of companies was renamed, and Terasen Inc. became FortisBC Holdings Inc., and Terasen Gas Inc. became FortisBC Energy Inc.

1.2 Fort Nelson Service Area

The natural gas distribution system in the Fort Nelson service area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and other companies and continued at that time as BC Gas Inc. (now FortisBC Energy Inc.).

Operations in Fort Nelson consist of a transmission lateral from the nearby Westcoast Energy Inc., (formerly owned by Duke Energy – BC Pipeline Division and now Spectra Energy) processing plant to the town of Fort Nelson together with a gas distribution system. Also included in the service area is the distribution system in Prophet River.

Rates have been set separately for the Fort Nelson service area from the date the company was acquired to the present. The Company sought regulatory consolidation of the Fort Nelson service area with the remainder of the Company in its 1992 Revenue Requirement Application, but the application was not approved. Since then, the Fort Nelson service area has been excluded from the Company's general revenue requirement applications and Performance Based Ratemaking plans.

1.3 Summary

FEI, a wholly owned subsidiary of FortisBC Holdings Inc., provides natural gas transmission and distribution services to approximately 840,000 residential, commercial, and industrial customers in approximately 100 communities on the mainland including the Inland, Columbia, Fort Nelson, and Lower Mainland service areas. Service is provided through approximately 40,000 kilometres of distribution mains and transmission pipelines.

2 FORTISBC ENERGY (VANCOUVER ISLAND) INC.

FortisBC Energy (Vancouver Island) Inc. ("FEVI")[2] is a company incorporated under the laws of the Province of BC offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

[2] Formerly known as Terasen Gas (Vancouver Island) Inc. ("TGVI"), Centra Gas British Columbia Inc. and Pacific Coast Energy Corporation ("PCEC")

The Company began distribution of natural gas on Vancouver Island and the Sunshine Coast in 1991, at which time natural gas was first available to those communities through the Vancouver Island Natural Gas Pipeline. FEVI's predecessor, PCEC, operated the high pressure transmission pipeline and three Centra companies (Centra Gas British Columbia Inc. (Inc. No. 0060334), Centra Gas Victoria Inc. (Inc. no 0356486) and Centra Gas Vancouver Island Inc. (Inc. no 0355320)) operated the distribution systems. On January 1, 1996, PCEC acquired, by way of asset transfer agreement, the assets of the three Centra companies. On January 1, 1996, PCEC changed its name to Centra Gas British Columbia Inc. ("Centra Gas")". In 2002, BC Gas Inc. purchased Centra Gas, and in 2003, BC Gas Inc. changed its own name and the names of each of its corporate entities, with the holding company becoming Terasen Inc. and Centra Gas becoming Terasen Gas (Vancouver Island) Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc., and on March 1, 2011, the Terasen group of companies was renamed, and Terasen Inc. became FortisBC Holdings Inc., and Terasen Gas (Vancouver Island) Inc. became FortisBC Energy (Vancouver Island) Inc.

Today, FEVI, a wholly owned subsidiary of FortisBC Holdings Inc.[3], provides natural gas transmission and distribution services to approximately 100,000 residential, commercial, and industrial customers in approximately 40 communities on Vancouver Island and the Sunshine Coast. Service is provided through approximately 4,160 kilometres of pipelines.

3 FORTISBC ENERGY (WHISTLER) INC.

FortisBC Energy (Whistler) Inc. ("FEW")[4] is a company incorporated under the laws of the Province of BC offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

Until 2009, Whistler was serviced by a piped propane distribution system. In April 2009, the construction of the natural gas pipeline lateral connecting the Resort Municipality of Whistler (the "RMOW") to the transmission system of FEVI was completed. From May to August of 2009, the piped propane system and customer appliances were converted to natural gas. The distribution system now consists of an underground distribution piping system and IP/DP station at Function Junction in Whistler. Natural gas is received at the IP/DP station from the Intermediate Pressure Line of FEVI which interconnects with the FEVI transmission line at FEVI's Squamish station.

The prior propane gas distribution system in Whistler was established in 1980 and was originally owned and operated by the RMOW. In 1985 ICG Liquid Gas Ltd. ("ICG") purchased the distribution system from the RMOW in a sale authorized by the Minister of Municipal Affairs. In addition, the Commission granted ICG an exemption from the *Utilities Commission Act* (the

[3] Formerly Terasen Inc.
[4] Formerly known as Terasen Gas (Whistler) Inc. ("TGW"), Centra Gas British Columbia Inc. and Centra Gas Whistler Inc.

"Act"), S.B.C. 1980 c.60, until December 31, 1994. In 1987, ICG Utilities (British Columbia) Ltd. ("ICG Utilities") purchased the distribution system, resulting in the exemption from regulation, pursuant to Section 103(3) of the Act being vacated.

Westcoast Energy Inc. ("WEI") acquired ICG Canada Inc, including ICG Utilities in April 1990. Later that year in November, ICG Utilities became Centra Gas British Columbia Inc. ("CGBC"). CGBC operated the Whistler system from 1990 to 1995. In 1996, CGBC was restructured and the Whistler-based assets of the company were transferred to a new company, Centra Gas Whistler Inc. In March 2002, BC Gas Inc. purchased Centra Gas Whistler Inc. from WEI. In 2003, BC Gas Inc. changed its own name and the names of each of its corporate entities, with the holding company becoming Terasen Inc. and Centra Gas Whistler Inc. changed its name to Terasen Gas (Whistler) Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc., and on March 1, 2011, the Terasen group of companies was renamed, and Terasen Inc. became FortisBC Holdings Inc., and Terasen Gas (Whistler) Inc. became FortisBC Energy (Whistler) Inc.

Today, FEW, a wholly owned subsidiary of FortisBC Holdings Inc.[5], provides natural gas transmission and distribution services to approximately 2,600 residential and commercial customers in Whistler. Service is provided through approximately 125 kilometres of pipelines.

4 THE FORTISBC ENERGY UTILITIES

On March 1, 2011, the Terasen group of companies was renamed to the FortisBC brand. FortisBC Holdings Inc.[6] (the holding company of the natural gas utilities) is a wholly-owned subsidiary of Fortis Inc.. Fortis Inc. is the largest investor-owned distribution utility in Canada. The gas distribution utilities in BC are currently organized as three wholly-owned subsidiaries of FortisBC Holdings Inc., specifically FEI, FEVI, and FEW, collectively referred to as the FortisBC Energy Utilities (the "FEU").

Today, the FEU combined are the largest natural gas distribution utility in BC, providing sales and transportation services to residential, commercial, and industrial customers in more than 140 communities throughout the Province, with in excess of 940,000 customers served throughout the province. The FEU own and operate natural gas pipelines and natural gas distribution facilities in BC, including approximately 44,000 kilometres of transmission pipelines and distribution mains. The FEU's distribution network serves close to 88 per cent of natural gas customers in BC and delivers more than 20 per cent of the total energy consumed in Province.

[5] Formerly Terasen Inc.
[6] Ibid

Appendix B-2

REGULATORY HISTORY

REGULATORY HISTORY

1 FORTISBC ENERGY INC.

For the 2010 and 2011 period, the Commission approved a two-year Negotiated Settlement Agreement for FortisBC Energy Inc. [1] ("FEI") which, among other things, allowed the utility to pursue Thermal Energy Solutions[2] through the use of a deferral account to record revenues and costs associated with Thermal Energy business to be allocated to Thermal Energy customers.

In the 15 years prior to 2010, the regulatory model used to set rates for FEI moved away from traditional cost of service regulation towards incentive-based ratemaking models. From 1994 to 2009, FEI had operated under an evolving model of performance-based ratemaking ("PBR") through settlements negotiated with customers and approved by the Commission. PBR models seek to enhance the performance of utilities through the use of incentive mechanisms not found in traditional cost of service regulation. A common theme that emerges is the need to break or weaken the link between costs and rates so as to enhance the incentive for utilities to reduce costs. In the regulatory processes leading to the past PBR plan settlements, parties have participated in the exchange of information, commentary, workshops, analyses, negotiations and settlement discussions. The processes culminated in agreements containing incentives to enhance utility performance while maintaining excellent customer service, and established ongoing annual reviews to monitor the PBR results in a Commission sponsored process. The comprehensive PBR plans (1998-2001 and 2004-2009) have also included earnings sharing mechanisms by which customers have shared in the benefits achieved. Therefore, these settlements have moved the interests of FEI and customers into closer alignment and have encouraged the attainment of greater efficiencies.

In 1997, the Commission approved a PBR Plan for the three years from 1998 to 2000. In 2000, by agreement of customers and FEI, and as approved by the BCUC, the PBR Plan was extended to include 2001. During this period, FEI undertook initiatives to meet and exceed productivity targets in the PBR Plan without deterioration in the quality of service to customers. These initiatives led to a significant reduction of FEI's workforce and to the achievement of operating cost per customer efficiencies. Although FEI achieved a high level of performance in the area that was the primary focus of the incentives in the 1998 - 2001 PBR Plan, namely O&M expenses, the delivery rates of FEI increased during this term of the PBR Plan. The primary driver of this increase was the necessary and required investment in capital to provide safe, reliable and efficient service to customer. Under the 1998 - 2001 PBR Plan, the extent to which FEI could recover restructuring costs was dampened by the absence of an adequate multi-year payback mechanism in the areas of capital expenditures and operating costs.

[1] Formerly Terasen Gas Inc.
[2] Previously referred to as Alternative Energy Solutions, which includes Geo-exchange, Solar-thermal and District Energy Systems

On August 24, 2001 FEI filed a revenue requirements application for 2002 seeking a 7 percent increase in delivery rates, corresponding to an approximate 2 percent increase in burner-tip rates. On November 1, 2001, FEI filed notice with the Commission that it was withdrawing its 2002 revenue requirements application. After an information session regarding the application withdrawal on November 8, 2001 and intervener submissions on November 9, 2001 the Commission issued Order No. G-123-01 and Reasons for Decision approving the withdrawal of the application and directing FEI to address certain matters raised in the Reasons for Decision in its 2003 Revenue Requirements Application. As a result, the 2001 base delivery rates remained in effect throughout 2002.

On June 17, 2002, FEI filed a 2003 Revenue Requirements and Multi-Year Performance-Based Ratemaking Application seeking approval for its 2003 revenue requirements, approval to determine its 2003 rates and to establish a comprehensive multi-year performance-based rate plan for 2003 to 2007 through a negotiated settlement process. A public hearing was held commencing November 12, 2002 for the review of 2003 revenue requirements and the Commission issued its Decision and Order G-7-03 on February 4, 2003. That Decision reviewed FEI's costs and revenues, and established rates for 2003. At page 53, the Commission's Decision stated:

> *"The Commission anticipates that [FEI] will file, early in 2003, a multiyear PBR Application for revenue requirements for 2004 and beyond which incorporates the determinations made in this Decision. The Commission would then establish a procedure in accordance with the Commission's Negotiated Settlement Process Guidelines."*

On April 17, 2003, FEI filed its Multi-Year PBR Plan for 2004 – 2008. Following a Negotiated Settlement Process, the Commission accepted the agreement reached by the parties, by Order No. G-51-03 dated July 29, 2003. The agreement was based on a four-year term rather than the proposed five-year term and thus approved the 2004-2007 Multi-Year Performance-Based Rate Plan Settlement (the "2004-2007 PBR Settlement Agreement"). The key elements in this order included:

- Allowed O&M costs and base capital expenditures set on an incentive formula basis;
- 50:50 sharing between customers and FEI of achieved efficiencies (after paying for restructuring costs) beyond those already embedded in the O&M and the base capital expenditure formulas;
- Restructuring costs funded through achieved efficiencies, not from customers;
- Mechanisms to continue the incentive to invest in efficiencies throughout the term of the plan;
- Results-based Service Quality Indicators;
- 4-year term with opportunity for mid-term review/adjustments; and

- An Annual Review process and other provisions to keep customers informed of the functioning of PBR settlement agreement such as a mid-term review process and the formation of a Customer Advisory Council.

In carrying out the provisions of the 2004-2007 PBR Settlement Agreement FEI delivered significant value to its customers relative to what would have been achieved under traditional cost of service regulation. Some of the benefits achieved include lower delivery rates through achieved efficiencies, greater certainty in delivery rates by establishing results-based formulas and improved regulatory and administrative efficiency. The most important benefit of PBR is that it fostered strong alignment between customer and company interests by encouraging innovation, customer focus and the on-going pursuit of operating efficiencies. The interests of customers were also well served in the 2004-2007 PBR Settlement through other means such as the Customer Advisory Council (which met twice yearly during the PBR term), the requirement for FEI to meet and measure customer service levels through an extensive set of Service Quality Indicators ("SQIs"), Annual Reviews and the Mid-term Assessment Review.

For 2004 and onwards, FEI was required to update its forecast of customer additions, use per account and industrial revenues annually. The impact on revenues resulting from the updated forecasts would be flowed through in delivery rates in the following year. The settlement also provided for the flow through of the impacts of changes approved by BCUC orders and exogenous factors. The terms of the Settlement Agreement also required FEI to hold a Mid-Term Assessment Review to provide an expanded annual review and information on its current and future year activities prior to the end of the third year (2006) of the Settlement Agreement.

On January 19, 2007, shortly after the Mid-Term Assessment Review, FEI filed its Application for the Approval of a Two-Year Extension (2008-2009) of the Settlement Agreement (the "Extended Settlement Agreement"). By Order No. G-33-07 dated March 23, 2007 the Commission approved the two-year extension of the 2004-2007 Multi-Year Performance-Based Rate Plan.

The annual reviews have been a process for FEI, customers and stakeholders to ensure that the objectives of the Settlement Agreement were being achieved and to review the cost drivers and financial forecasts for the purposes of establishing revenue requirements for the following year. FEI had performed well over the PBR period by delivering value to its customers. In addition to achieving efficiencies, FEI implemented comprehensive and customer-focused service quality assurance measures (SQIs) to ensure that service quality standards were maintained throughout the term of the PBR. Moreover, customers have received benefits from FEI's continued efficiencies through the 50:50 sharing mechanism, whereby significant amounts have been refunded to customers through Earnings Sharing Mechanism ("ESM") riders.

The following sections will provide a synopsis of FEI's annual review applications and the Commission's decisions for each year since 2003.

1.1 2003 Annual Review of 2004 Revenue Requirements

On October 31, 2003, FEI filed its Annual review advance material and on November 28, 2003, applied for approval of its 2004 revenue requirements and delivery rates, pursuant to section 58, 60 and 61 of the Act and the terms of the Settlement Agreement, for an increase to delivery rates by 4.3 percent to recover a revenue deficiency of $19.15 million. This filling also contained a business case study on the separation of FortisBC Holdings Inc. ("FHI") (then Terasen Inc.) and the creation of a corporate centre as directed in the 2003 Decision.

By Order No. G-80-03, dated December 17, 2003, the Commission approved FEI's request for an increase in delivery rates effective January 1, 2004. The key drivers contributing to the revenue requirements increase were:

- Lower residential and commercial use rates;
- Higher depreciation and amortization;
- Change in accounting for Transmission Pipeline Integrity Program ("TPIP") expenditures;
- Higher O&M per formula; and
- Higher rate base due to plant additions.

The Commission also approved the following:

- The cancellation of the ten-month rider that was established by Commission Order No. G-7-03. This rider recovered the foregone January/February 2003 rate increase over the remaining the months of 2003; and
- An increase in the Revenue Stabilization Adjustment Mechanism ("RSAM") rider by $0.061/GJ from $0.134/GJ to $0.195/GJ.

The Commission denied the following requests:

- The increase property tax incentive from 10 percent to 25 percent;
- The Utility Asset Utilization Incentive; and
- The incentive for pension and insurance costs similar to the property tax incentive mechanism.

1.2 2004 Annual Review of 2005 Revenue Requirements

On October 29, 2004, FEI filed its Annual Review advance materials and subsequently on November 26, 2004, FEI applied for approval of its 2005 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2005 revenue requirements calculations, according to the provisions of the Settlement Agreement, resulted in a revenue requirements decrease of $2.108 million. This revenue surplus corresponded to an overall 0.42 percent decrease in gross margin or a 0.15 percent decrease in revenue. After excluding bypass and special rate revenues, the decrease in delivery rates for customers subject to general revenue requirements decrease was 0.45 percent.

FEI also requested approval for the following:

- to decrease the RSAM rider applicable to the residential and commercial rate classes from $0.195/GJ to $0.143/GJ;
- ESM riders for the customers' portion of the projected 2004 earnings shortfall of $204,000, representing 0.04 percent of the gross margin;
- to transfer the balance of the Coastal Facilities assets into rate base and finance by 67 percent debt and 33 percent equity (the approved capital structure then in effect);
- to utilize customer security deposits as a substitute for short-term borrowing; and
- to establish deferral accounts for OSC compliance costs and BCUC levies, as the cost increases associated with these items were deemed to be exogenous factors.

By Order No. G-112-04 dated December 15, 2004, the Commission approved FEI's request for a decrease in delivery rates effective January 1, 2005. The key drivers contributing to the revenue requirements decrease were:

- Customer growth and industrial revenue changes;
- Higher other revenues from the Southern Crossing Pipeline ("SCP");
- Change in pension and insurance forecast;
- Lower income taxes;
- Large Corporations Tax rate reduction;
- Lower depreciation and amortization; and
- Change in use rates.

1.3 2005 Annual Review of 2006 Revenue Requirements

On October 19, 2005, FEI filed its Annual Review advance materials, followed on November 7, 2005, by a revision pursuant to Commission Order No. G-98-05, then subsequently on December 2, 2005, FEI applied for approval of its 2006 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2006 revenue requirements calculations, according to the provisions of the Settlement Agreement, resulted in a revenue requirements increase of $18.044 million. This revenue deficiency corresponded to an overall 3.68 percent increase in gross margin or a 1.10 percent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirements increase was 3.90 percent.

FEI also requested the following approvals:

- to continue the 2005 approved return on equity of 9.03 percent and common equity component of 33 percent for the purpose of setting interim rates for 2006;
- to increase the RSAM rider by $0.023/GJ from the currently approved level of $0.143/GJ to $0.166/GJ;
- customers' portion of the 2005 ESM surplus projected at $6.0 million on a pre-tax basis, equivalent to a refund of 1.30 percent of gross margin; and
- to establish deferral treatment for the net book value difference of $1.533 million resulting from the replacement on November 1, 2005 of the existing fleet service provider, from BC Hydro to PHH Arval, and to amortize over 3 years commencing January 1, 2006 this difference between BC Hydro's stated net book value and the fair market value assigned by PHH Arval.

On December 14, 2005, by Order No. G-132-05, the Commission approved FEI's 2006 request for an increase in delivery rates on an interim basis, pending the decision on FEI and FortisBC Energy (Vancouver Island) Inc. ("FEVI") 2005 Return on Equity ("ROE") and Capital Structure Application, effective January 1, 2006, subject to refund with interest at the average prime rate of FEI's principal bank. The key drivers contributing to the revenue requirements increase were:

- Lower use rates;
- Higher rate base due to plant additions;
- Lower revenue from the SCP; and
- Higher depreciation and amortization.

On March 2, 2006, the Commission issued its Decision and Order No. G-14-06 in the FEI-FEVI 2005 ROE and Capital Structure Application setting the ROE for FEI at 8.80 percent and its equity component at 35 percent.

1.4 2006 Annual Review of 2007 Revenue Requirements

On October 16, 2006, FEI filed its Annual Review advance materials which included a request that the Commission approve the amalgamation of FEI and Squamish (then Terasen Gas (Squamish) Inc.) ("Squamish"), effective January 1, 2007. On December 1, 2006, FEI applied for approval of its 2007 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Settlement Agreement. The 2007 revenue requirements calculations, according to the provisions of the Settlement Agreement, resulted in a revenue requirements decrease of $9.6 million. This revenue surplus corresponded to an overall 1.87 percent decrease in gross margin or a 0.65 percent decrease in revenue. After excluding bypass and special rate revenues, the decrease in delivery rates for customers subject to the general revenue requirements decrease was 0.60 percent. The key drivers contributing to the revenue requirements decrease were:

- Elimination of the large corporations tax;

- Lower rate base and others;
- Change in the pension and insurance forecast;
- Change in customer growth; and
- Higher income tax deductions.

By Order No. G-160-06, dated December 18, 2006, the Commission determined the following:

- Accepted FEI's opinion regarding the applicability of sections 41, 50, 52, 53 and 54 of the Act to the amalgamation of FEI and Squamish. The Commission agreed that Commission approval was not required for the amalgamation of FEI and Squamish. The Commission approved the cancellation of FEI Tariff Supplement I-3 and Squamish Tariff, effective January 1, 2007. In accordance with Special Direction No. 3, the Commission approved the amalgamated of FEI and Squamish;
- Approved the $0.021/GJ decrease in the Rate Stabilization Adjustment Mechanism rider from $0.166/GJ to $0.145/GJ, effective January 1, 2007;
- Approved customers' portion of the 2006 ESM surplus projected at $8.2 million on a pre-tax basis, representing 1.69 percent of the gross margin;
- Approved the establishment of a rate base deferral account to record the $10 million payment and the cost of the Social Service Tax appeal, subject to the $414 million SCP Project maximum capital cost approved by Commission Order No. G-95-00;
- Accepted FEI's submission that the inclusion of non-executive bonuses in pension costs recovered from customers and the exclusion of executive bonuses in pension costs recovered from customers is consistent with Commission's 1992, 1994 and 2003 Decisions;
- Accepted FEI's submission that terms of the Settlement prevent it from increasing the Demand-Side Management ("DSM") incentive grants over the $1.5 million during the period of the Settlement. FEI was instructed to include the Ratepayer Impact Measure test, the Participant Cost test and the percentage of "free riders" for the each program in the 2006 DSM portfolio and in future DSM reports.

1.5 Two-Year Extension of the 2004-2007 Multi-Year PBR Plan for 2008-2009

On January 19, 2007, FEI applied for approval of the Extended Settlement Agreement, effectively a two-year extension to the terms of the existing 2004-2007 Multi-Year PBR Plan Settlement Agreement for the years 2008 and 2009. During the regulatory review process for the Extended Settlement Agreement, on March 1, 2007, Fortis Inc. applied for approval of the acquisition of the issued and outstanding shares of FEI's parent (then Terasen Inc.) (the "Acquisition"). Interveners filed no objections or concerns regarding the Acquisition as it related to the Extended Settlement Agreement, and on March 23, 2007, the Commission issued Order No. G-33-07 approving the Extended Settlement Agreement.

1.6 2007 Annual Review of 2008 Revenue Requirements

On October 5, 2007, FEI filed its Annual Review advance materials and on November 30, 2007, FEI applied for approval of its 2008 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Extended Settlement Agreement. The 2008 revenue requirements calculations, according to the provisions of the Extended Settlement Agreement, resulted in a revenue requirements increase of $9.43 million, before consideration of the customer portion of the ESM. This revenue requirement corresponded to an overall 1.89 percent increase in gross margin or a 0.62 percent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirements was a 0.57 percent increase in revenue. After taking into consideration the earnings surplus incentive sharing of $15.0 million the revenue requirements was a decrease of $5.6 million, equivalent to a 1.1 percent decrease in gross margin. The further impact on revenue decrease was due to amended FEVI Wheeling Revenue and final FEI ROE decision of 8.62 percent. The key drivers contributing to the revenue requirements decrease were:

- Higher income tax deductions;
- Change in pension and insurance forecast;
- Lower depreciation and amortization; and
- Lower income tax rates.

By Order No. G-153-07, dated December 10, 2007, the Commission approved the following:

- The increase of applicable charges for most rate classes of customers, effective January 1, 2008, as provided in the Revised Application;
- Customers' portion of the 2007 incentive earnings surplus projected at $12.6 million on a pre-tax basis, representing 2.67 percent of the gross margin; the $0.05/GJ decrease in the RSAM rider from the currently approved level of $0.145/GJ to $0.095/GJ, effective January 1, 2008;
- the continuation of the rate base deferral account established for the ongoing Provincial Sales Tax appeal related to the SCP project;
- the establishment of a rate base deferral account to record any differences in the Service Line Installation fees and Service Line Cost Allowance resulting from the Commission Decision in the System Extension and Customer Connection Charges Review Application, to be amortized in the following year;
- the establishment of a rate base deferral account to record cost of service reductions related to the timing of the Lochburn land sale; and
- the request for FEI to follow Section 3061.04 of the CICA Handbook revision that will result in a reclassification in FEI's financial statements between inventory and property, plant and equipment for pipe, valves, fittings and other items that would ultimately be used for gas plant in service, whereby these costs will be transferred to Plant Work in

Process ("WIP") in the financial statements, effective January 1, 2009, as described in the Advance Materials.

1.7 2008 Annual Review of 2009 Revenue Requirements

On October 8, 2008, FEI filed the Annual Review advance materials and on December 3, 2008, FEI applied for approval of its 2009 Revenue Requirements and delivery rates pursuant to sections 58, 60 and 61 of the Act and the terms of the Extended Settlement Agreement. The 2009 revenue requirements calculations, according to the provisions of the Extended Settlement Agreement, resulted in a revenue requirements increase of $35.12 million, before consideration of the customer portion of the ESM. This revenue requirements corresponded to an overall 7.30 percent increase in gross margin or a 2.10 percent increase in revenue. After excluding bypass and special rate revenues, the increase in delivery rates for customers subject to the general revenue requirements was a 1.95 percent increase in revenue.

In addition, FEI requested deferral account treatment for incremental costs associated with the implementation of International Financial Reporting Standards ("IFRS") to be amortized beginning in 2011, a deferral account treatment of incremental costs for Olympic and Paralympic Games Security to be amortized beginning 2011, a change to the amortization of the Large Corporations Tax deferral account, and changes to the non rate base Residential and Commercial Commodity Unbundling deferral accounts.

The key drivers contributing to the revenue requirements increase were:

- Change in use rate;
- Higher depreciation and amortization;
- Higher property taxes;
- Higher O&M;
- Lower income tax deductions; and
- Higher rate base to support customer growth.

By Order No. G-191-08, dated December 11, 2008, the Commission approved the following:

- Customers' portion of the 2008 incentive earnings surplus projected at $12.0 million on a pre-tax basis, representing 2.61 percent of the gross margin;
- The $0.093/GJ decrease in the RSAM rider from the currently approved level of $0.094/GJ to $0.001/GJ effective January 1, 2009;
- The establishment of a rate base deferral account to recover the critical security costs associated with the 2010 Olympic and Paralympic Winter Games;
- The establishment of a rate base deferral account to recover the incremental costs associated with IFRS implementation;
- The change to the amortization of the Large Corporations Tax deferral account; and

- The changes to the non-rate base Residential and Commercial Commodity Unbundling deferral accounts.

FEI was ordered to revise its 2009 forecast to account for any direction from the review of the Customer Choice operating and capital expenditure budgets. The Commission also ordered that if there is delay in the issuance of the Customer Choice Decision then FEI should record the difference between the 2009 budget and the 2009 allowed operating expenditures and capital expenditures in rate base deferral accounts for disposition in the next year's revenue requirements.

1.8 2010-2011 Revenue Requirements Negotiated Settlement Agreement

On June 15, 2009, FEI filed an application for approval of its 2010 and 2011 Revenue Requirements, pursuant to sections 59 to 61 and 89 of the Act, seeking an increase in delivery rates for a two-year period. The increase sought for 2010 was equivalent to an approximate effective base delivery rate increase of 5.3 percent and for 2010 a further 4.1 percent in 2011 (cumulative 9.4 over both years). The revenue requirements increase identified for 2010 was $27.9 million and for 2010 was $21.9 million.

Notable in the application were the significant changes taking place in the external operating environment, including:

- Evolving energy and environmental policies;
- The changing expectations of customers, regulators, and other stakeholders;
- FEI's level of competitiveness as an energy provider; and
- Changing economic and demographic realities.

The single, most significant key driver contributing to the revenue requirements increase was the accounting changes associated with the adoption of new accounting standards. But for the accounting changes, the revenue requirements would have indicated a rate decrease for 2010 and a small increase for 2011. Other key drivers contributing to the revenue requirements increase were:

- Change in use rate;
- Lower capital expenditures;
- Lower O&M;
- Lower depreciation and amortization;
- Higher property taxes;
- Lower income tax deductions; and
- Higher rate base to support customer growth.

A Negotiated Settlement Process commended on October 21, 2009 and concluded on November 3, 2009, and on November 26, 2009, the Commission issued Order No. G-141-09 approving the 2010-2011 NSA including, among other things, the following:

- Delivery rates remain unchanged and that the 2010 forecast revenue surplus of $9.2 million be recorded in a rate base deferral account, entitled 2010 Revenue Surplus Deferral Account, and be applied to offset any forecast increase in delivery rates in 2011 (subject to changes from the impending decision on the FEU 2009 ROE and Capital Structure Application);
- Continue tracking and posting on the FEI website the SQIs as set out in the prior PBR Agreement and extension thereto;
- Revise the customer additions forecast to 5,952 in 2010 and 6,166 in 2011, and the 2009 year end number of customers to 835,862;
- Revise the Residential annual user per customer to 91.7 in 2010 and to 90.3 in 2011;
- Revise the industrial demand forecast in 2010 to 46.5 PJ and in 2011 to 46.5 PJ;
- Continue to include the annual cost of SCP capacity of $3.6 million in the MCRA;
- EEC Funding for 2010:
    - Reallocate from residential and commercial EEC programs an additional $1.6 million to low income and rental housing programs (bringing the total of for those programs to $2.4 million for 2010);
    - Industrial interruptible programs funding be $435,000;
    - Innovative technologies funding be $2.3 million, and will be managed as a separate segment of the overall portfolio and have a weighted average Total Resource Cost of 1.0 or more;
- EEC Funding for 2011:
    - Residential and commercial program funding for 2011 be $23.075 million;
    - Reallocate from residential and commercial EEC programs an additional $1.6 million to low income and rental housing programs (bringing the total of for those programs to $2.4 million for 2011);
    - Industrial interruptible programs funding be $1.875 million
    - Innovative technologies funding be $4.669 million, and will be managed as a separate segment of the overall portfolio and have a weighted average Total Resource Cost of 1.0 or more;
- Alternative Energy Solutions (now referred to as Thermal Energy Solutions or “Thermal Energy”):
    - Thermal Energy means Geo-exchange, Solar-thermal and District Energy Systems;
    - Cost incurred to provide Thermal Energy will be recorded in a deferral account, entitled, “New Energy Solutions Deferral Account”, attracting AFUDC, and will capture and record:
        - Direct costs associated with projects;

- Sales and marketing O&M and other development costs charged directly to the deferral account by time sheet or direct charge (estimated to be $1.0 million in 2010 and $1.5 million in 2011;
- An agreed upon overhead allocation of $500,000 in each of 2010 and 2011;
- Revenue from Thermal Energy customers;
- Revenue and costs be captured on a project-specific basis and reported as part of the next Revenue Requirements application;

- Natural Gas for Vehicles ("NGV"):
  - Rate Schedule 26 – NGV Transportation Service was approved and costs as applied for in support of NGV be recovered in 2010 and 2011 rates;
  - Marketing costs in support of NGV included in the application are appropriate and recoverable in 2010 and 2011 rates;
- CPCN Threshold to remain at $5 million;
- Category A Capital be $43.3 million for 2010 and $46.0 million for 2011;
- Category B Capital be $17.4 million in 2010 and $14.9 million in 2011;
- Category C Capital be $32.8 million in 2010 and $32.7 million in 2011;
- Reduction in O&M from the amount requested in the Application by $4.0 million in 2010 and by $5.5 million in 2011, with a resulting reduction to the Shared Services and Corporate Services allocations;
- Total depreciation expense of $98.3 million in 2010 and $100.5 million in 2011;
- An estimate of net removal costs of $8.038 million in 2010 and $11.29 million in 2011 be included in the cost of service, with the variance between actual realized net removal costs and the estimated amounts be recorded in a new deferral account, entitled "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two-year period will be recovered from or returned to customers in 2012;
- Include the full value of the incremental tax benefit with the difference in CCA rates for 2007 and 2008 totalling $921,000;
- Tax benefits relating to prior periods for SCP Landscaping costs reducing revenue requirements for 2010 by approximately $7.9 million and in 2011 by approximately $2.3 million;
- Change in the Overheads Capitalized rate to 14 percent of Gross O&M for 2010 and 2011;
- A maximum of $1.0 million of the 2010 revenue requirements impact of IFRS be recovered in 2011, with amounts, if any, over $1.0 million be deferred and recovered in rates after 2011;
- Maintaining the existing Code of Conduct and Transfer Pricing Policy;

- Various accounting policy changes, accounting related proposals, tariff changes, and deferral account changes were approved as applied for;
- Allocation of delivery margin rate changes - Annual margin increase allocated to variable (volumetric & demand) based delivery charges, with no change to fixed (basic and admin fee) charges in each year;
- ESM rider (incl. end of term capital) - Change the ESM rate rider to be ($0.040)/GJ effective January 1st, 2010, and change the estimated ESM rate rider to be ($0.046)/GJ effective January 1st. 2011. ESM amount to include End of Term Capital phase out and to be amortized over two years. The final 2011 rider amount will be adjusted based on 2009 actual earnings. TGI will submit an application to change the 2011 ESM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010; and
- RSAM rider - Change the RSAM rate rider to be ($0.053)/GJ effective January 1st, 2010 and change the estimated RSAM rate rider to be ($0.052)/GJ effective January 1st, 2011. The 2011 rider amount will be adjusted based on 2009 actual results and 2010 year to date actual results. TGI will submit an application to change the 2011 RSAM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010.

As part of reaching the Agreement with the Parties and upon acceptance of the Agreement by the Commission, FEI agreed to withdraw its requests related to NGV and Biogas as follows:

- NGV:
  - Rate Schedule 6C NGV Compression and Refueling Service and Rate Schedule 6A NGV Refueling Service;
  - The Compression Service Test;
  - NGV non-rate base deferral account; and
  - The Parties agreed that the withdrawal of the requests was done without prejudice to FEI’s right to bring forward similar requests in 2010, 2011 or in the future; acknowledged that FEI intended to develop this area of business; and FEI anticipated bringing forward applications on NGV projects on a case-by-case basis.
- Biogas:
  - All requests related to Biogas; and
  - the Parties agreed that FEI would bring forward an application for Biogas (the “Biogas Application”) during the test period that would:
    - Address the economic assessment model;
    - Provide Biogas rates (including green rate, transportation rate, etc.);
    - Provide recovery of costs associated with providing Biogas service; and

- FEI may include any Biogas Projects under development at that time and that FEI may apply for Commission approval of individual Biogas Projects at any time, either prior to the Biogas Application or afterward.

Further, on December 16, 2009, the Commission issued its Decision and Order No. G-158-09 on the FEU 2009 ROE and Capital Structure Application setting the ROE for FEI to 9.50 percent effective July 1, 2009, and that the appropriate equity ratio be 40 percent effective January 10, 2010.

1.9 Summary

As discussed above, FEI has lived up to the expectations of its regulatory commitments through the settlement periods. During these periods, FEI performed well by achieving efficiencies and maintaining customer-focused service quality standards. Consequently, the settlement agreements since 2003, coupled with annual reviews, have served their purpose by aligning the interest of FEI's customers, stakeholders, and shareholder.

1.10 Fort Nelson Region

Rates have been set separately for the FEI Fort Nelson region from the date the company was acquired to the present. FEI (then as BC Gas Utility Ltd.) sought regulatory consolidation of the Fort Nelson service area ("Fort Nelson") with the remainder of FEI in its 1992 Revenue Requirement Application, but the application was not approved. Since then, Fort Nelson has been excluded from FEI's general revenue requirements applications and PBR plans.

Fort Nelson's gas supply has typically been obtained through one contract. In recent years, FEI has used a small portion of its contracted gas storage capacity at Aitken Creek to improve the load factor of Fort Nelson and to mitigate the impact of gas volatility for Fort Nelson customers. The diversity of FEI's overall gas supply portfolio has assisted over the years in providing favourable gas supply arrangements for Fort Nelson.

Customers in Fort Nelson have benefited and continue to benefit in various ways from being part of a much larger gas distribution company. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities;
- Access to low cost capital funding;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and
- Access to the commodity-related benefits of being in a company that is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs.

Since 1985, most rate changes have been limited to those approved from time to time for flow-through cost of gas increases or decreases.

In 1995, delivery rates were decreased by 15.04 percent. Delivery rates thereafter remained unchanged until 2004, when there was a slight revenue requirements increase of $49,000 (1.08 percent increase in delivery rates), approved by Commission Order No. G-17-04, effective January 1, 2004.

On November 30, 2007, Fort Nelson filed its 2008 Revenue Requirements Application requesting an increase effective January 1, 2008. As a result of the regulatory review process, on February 28, 2008, the Commission issued Order No. G-27-08 which approved a revenue requirements increase of $227,000. That revenue requirements change was primarily attributed to the downturn of the forest industry affecting the industrial demand for the Fort Nelson region.

On November 20, 2008 by Order No. G-172-08, the Commission approved an increase in rates for Fort Nelson, effective January 1, 2009, to recover a revenue deficiency of $377,000, resulting in an average 6.7 percent rate increase for all sales rate classes or a 36.0 percent increase on a gross margin basis for all customers. This increase was required primarily due to a decline in industrial demand and use rates per customer.

On December 3, 2009 by Order No. G-147-09, the Commission approved the continuation in 2010 of the approved 2009 rates, effective January 1, 2010, and the creation of two new deferral accounts along with the continuation of existing deferral accounts, and changes to the RSAM rate rider. These requests were driven primarily by changes to Fort Nelson's return on equity and capital structure, and the proposed adoption by FEI of updated depreciation rates and overheads capitalized rate.

Most recently, on February 4, 2011, by Order No. G-27-11, the Commission approved an increase in rates for Fort Nelson, effective January 1, 2011, to recover a revenue deficiency of $315,000 resulting in an increase of 21.74 percent. The Commission also approved the continuation of existing deferral accounts and the adoption of accounting and other policy changes consistent with FEI in its 2010-2011 NSA. Also approved was the proposed 2011 capital expenditure of $3,015,650 to be included in rate base, related to the Muskwa River Crossing Project, directing that the total amortization/depreciation be recorded as a reduction to the carrying amount of the Project Assets in 2012 and that the Project Assets not attract Allowance for Funds Used During Construction ("AFUDC") after the projected in-service date of October 1, 2011.

2 FORTISBC ENERGY (VANCOUVER ISLAND) INC.

For the 2010 and 2011 period, the Commission approved a two-year Negotiated Settlement Agreement for FEVI which, among other things, allowed the utility to pursue Thermal Energy Solutions[3] for Vancouver Island customers through FEI.

Prior to 2010, FEVI was covered by settlement agreements, and the annual reviews and settlement updates over the 2003 to 2009 timeframe had been a process for FEVI and stakeholders to ensure that the objectives of settlement agreements were achieved and to review the cost drivers and financial forecasts for the purposes of establishing revenue requirements for the following year. The results of these settlements have helped to align the interest of FEVI and its customers.

What follows, is a synopsis of the FEVI's regulatory history by reviewing FEVI (and its predecessor companies) applications and Commission decisions for each year since 2003.

2.1 2003-2005 Revenue Requirements

On July 31, 2002, FEVI (then Centra Gas British Columbia Inc.), applied for approval of its 2003 – 2005 Revenue Requirements, which it proposed be reviewed through a Negotiated Settlement Process. That application was the first application in a two-phase process, with the second application to address rate design and rates. A Negotiated Settlement was reached among participants and the 2003 – 2005 Revenue Requirements application was approved by Commission on January 14, 2003 by Order No. G-2-03.

The Revenue Requirements Settlement agreement set out several items including, but not limited to: a three year term 2003 through 2005, items-at-risk for FEVI, gross allowed O&M expenses, depreciation rates, amortization, capital expenditure forecasts, a Gas Cost Variance Account ("GCVA"), capital structure and return on equity and the treatment of revenues variances with respect to the Revenue Deficiency Deferral Account ("RDDA"). Specifically, FEVI forecast the following:

- Revenue requirements to be $169,357,177 in 2003, $179,186,012 in 2004, and $184,046,880 in 2005;
- Utility rate base of $442,193,2077 in 2003, $446,480,221 in 2004, and $448,914,850 in 2005;
- Cost of sales to be $74,373,459 in 2003, $77,398,574 in 2004, and $80,730,206 in 2005
- Gross operating, maintenance, general and administrative expenses to be $32,919,154 in 2003, $34,810,466 in 2004, and $35,093,301 in 2005; and
- Operating and maintenance to be $5,408,154 in 2003, $5,526,728 in 2004, and $5,677,256 in 2005.

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[3] Previously referred to as Alternative Energy Solutions, which includes Geo-exchange, Solar-thermal and District Energy Systems

Through the Negotiated Settlement to the 2003-2005 Revenue Requirements Application, FEVI was to provide annual updates to ongoing operations and information on known and forecast changes affecting next period rate recommendations via an Annual Review process.

2.2 2003 Annual Review of 2004 Revenue Requirements

On November 12, 2003, FEVI filed its 2003 Annual Review of 2004 Revenue Requirements advance material for the following purpose:

1. Review and approve FEVI's 2002 actual cost of service and revenue deficiency results;
2. Update the forecast 2003 cost of service and revenue deficiency for known changes; and
3. Establish the 2004 test year cost of service and resulting rates for each class of effective January 1, 2004.

The forecast of 2004 revenue requirements indicated an annual revenue deficiency of $9.3 million. The key drivers contributing to this revenue deficiency were:

- Lower adjusted cost of gas
- Lower income tax
- Lower return on rate base
- Lower amortization of GCVA
- Lower sales rates and revenues

The Commission, by Order No. G-81-03 dated December 15, 2003, approved the following:

- The 2002 actual revenue requirements as filed in the Application and a 2002 revenue deficiency of $2,873,609 with a cumulative balance in the RDDA of $87,910,503 at the end of 2002;
- The creation of an Apartment Rate Class, AGS, to replace the existing ACR-2 rate class that expired on December 31, 2003 as required by the Special Direction;
- The rates effective January 1, 2004 for RGS, AGS, LCS-1, LCS-2, LCS-3, LCS-13, HLF, Firm Transportation and Interruptible Transportation classes as proposed in the Application;
- 2004 OM&A capitalization of $5,028,115;
- The 2004 Royalty-Adjusted unit cost of gas of $3.753/GJ is accepted based on a sales forecast of 11.4 PJ; and
- The incremental OM&A costs of the Sooke extension were approved as forecast in the Sooke CPCN Application.

2.3 2004 Annual Review of 2005 Revenue Requirements

On November 5, 2004, FEVI filed its 2004 Annual Review of 2005 Revenue Requirements advance material for the following purpose:

1. Review and approve FEVI's 2003 actual cost of service and revenue surplus results;
2. Update the forecast 2004 cost of service and revenue surplus for known changes, and;
3. Establish the 2005 test year cost of service and resulting rates for each class of effective January 1, 2005.

On November 26, 2004, FEV filed its Revised Application providing the most current forecast results for 2005 revenue requirements indicated an annual revenue surplus of $3.5 million. The key drivers contributing to this revenue surplus were:

- Higher adjusted cost of gas
- Lower income tax
- Higher return on rate base
- Amortization of GCVA
- Higher sales revenues

The Commission by its Order No. G-113-04, dated December 15, 2004, approved the following:

- The 2003 actual revenue requirements as filed in the Revised Application and a 2003 revenue surplus of $12,622,751 with a cumulative balance in the RDDA of $75,287,752 at the end of 2003;
- The 10 percent SAP Operating Lease charge from FEI to FEVI was appropriate and the calculation of the lease was to be based on FEI's cost of service;
- The $8.00 million of capital additions for FEVI related to the Utilities Strategy Project;
- The allocation of Shared Services costs to FEVI as proposed in the Revised Application;
- The 10 percent allocation of Gas Supply Core Market Administration Expense to FEVI as proposed in the Revised Application;
- The permanent rates effective January 1, 2005 for RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF, and ILF rate classes as proposed in the Revised Application;
- The Amending Agreement between FEVI and VIGJV;
- Charging interim firm and interruptible rates, effective January 1, 2005, to BC Hydro that were equal to the existing rates;
- The 2005 capitalization of OM&A of $4,626,494;

- The 2005 Royalty Adjusted unit cost of gas of $4.29/GJ based on a sales forecast of 11.9 PJ;
- Setting the October 1, 2004 GCVA Rate Rider D to zero effective January 1, 2005. The Commission approved the amortization of the forecast December 31, 2004 balance of the GCVA into rates;
- The 2005 incremental OM&A costs of $22,000 from the Sooke extension; and
- Directed that $78,500 be removed from project costs for the Sooke extension.

2.4 2006 – 2007 Revenue Requirements

On July 20, 2005, FEVI applied for approval of its forecast rates and Cost of Service for the years 2006 and 2007 and its Revenue Deficiency deferral Account balance as at December 31, 2004. On November 22, 2005, following the conclusion of a negotiated settlement process, the Commission issued Order No. G-126-05, dated November 30, 2005, approving FEVI's 2006-2007 Negotiated Settlement Agreement, which included:

- The 2004 revenue surplus of $14,243,422 with a cumulative balance in the Revenue Deficiency Deferral Account of $61,044,330 at the end of 2004.
- Interim rates effective January 1, 2006 for RGS, AGS, SCS-1, SC2-2, LCS-1, LCS-2, LCS-3, HLF, and ILF rate classes as proposed in the Negotiated Settlement.
- Interim rates effective January 1, 2006 for Firm Transportation, summer Interruptible Transportation, and winter Interruptible Transportation rates as proposed in the Negotiated Settlement.

Under the terms of the Negotiated Settlement Agreement, FEVI was to submit to the Commission and interested parties advance materials for the Settlement Update Filing three weeks prior to a Settlement Update Meeting. The details of the Settlement Update Meeting were set out in Item 15, Page 11 of Appendix A to the Settlement Order, specifically:

> *The parties agree that in the particular circumstances of the negotiation respecting revenue requirements and rates for 2006 and 2007 that a Settlement Update Meeting will be held in November 2006, rather than the customary Annual Review. The purpose of the Settlement Update Meeting will be for the Company to provide an update on the operations of the Company through 2006 and the outlook for 2007, with customers being provided the opportunity to make submissions regarding these matters. FEVI will provide a minimum 3 weeks written notice of the meeting, and will include with that notice updated information set out in Schedules 1 to 34B and in the tables provided by FEVI in response to BC Hydro's IR 4 from the 2006-2007 Revenue Requirements Application.*
>
> *FEVI will advise participants in this process of any significant applications it makes to the Commission.*

The 2006 Settlement Update Meeting was a process whereby TGVI and stakeholders could ensure that the objectives of the Settlement were being achieved. Specifically, at the Settlement Update meeting, FEVI was to:

- Provide an update on operations through 2006;
- Review the cost drivers and financial forecasts for the purposes of establishing the 2007 revenue requirements; and
- Provide an update on the undertakings identified in Appendix A to the Settlement Order.

2.5 2006 Settlement Update of 2007 Revenue Requirements

On October 23, 2006, FEVI filed its 2006 Settlement Update filing and application in accordance with the 2006-2007 Negotiated Settlement Agreement, and on November 24, 2006, FEVI filed its Revised Application. FEVI requested Commission approval for the following:

- Rates set forth to be effective January 1, 2007;
- Forecast Cost of Service (Revenue Requirements) for 2007;
- Allowable capital expenditures forecast for 2007, other than those expenditures that require a Certificate of Public Convenience and Necessity ("CPCN");
- Forecast revenue proposed for 2007; and
- The December 31, 2005 year- end balance in the RDDA.

By Order No. G-161-06 dated December 18, 2006, the Commission approved the following:

- The December 31, 2005 year-end balance in the Revenue Deficiency Deferral Account in the amount of $48,731,214;
- Permanent rates effective January 1, 2007 for RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF, and ILF rates classes as proposed in the Revised Application. The Commission also approved permanent rates effective January 1, 2007 for Firm Transportation, summer Interruptible Transportation, and winter Interruptible Transportation rates as proposed in the Revised Application;
- The forecast Cost of Service and Revenues for 2007 as filed in the Revised Application; and
- Allowable capital expenditures for 2007, other than those expenditures that require a CPCN, which will be reviewed in separate regulatory processes, as included in the Revised Application.

2.6 2008-2009 Extension of 2006-2007 Settlement

On January 22, 2007, FEVI filed its application for approval of a two-year extension of the 2006-2007 Revenue Requirements Negotiated Settlement Agreement terms for 2008 and 2009 (the

"FEVI Extended Settlement Agreement"). By Order No. G-34-07 dated March 23, 2007, the Commission approved the two-year extension.

The Commission directed that FEVI provide an Integrity Management Plan for Pipeline Facilities commencing for the 2007 forecast year and annually up to and including 2010.

2.7 2007 Settlement Update of 2008 Revenue Requirements

On October 5, 2007, FEVI filed its 2007 Settlement Update filing in accordance with the FEVI Extended Settlement Agreement. Further on November 2, 2007, FEVI filed a amendment, and on November 30, 2007, FEVI filed its Revised Application to update the 2008 ROE for FEVI to 9.32 percent in response to the Commission setting the benchmark ROE at 8.62 percent pursuant to Commission Letter No. L-93-07. In the application, FEVI requested Commission approval for:

- Rates set forth to be effective January 1, 2008;
- Forecast Cost of Service (Revenue Requirements) for 2008;
- Allowable capital expenditures forecast for 2008, other than those expenditures that require a CPCN;
- Forecast revenue proposed for 2008;
- The December 31, 2006 year- end balance in the RDDA; and
- Departure from using the Uniform System of and to prepare reports using the New Code of Accounts, providing both a resource-based view and an activity-view.

By Order No. G-154-07, dated December 11, 2007, the Commission approved the following:

- The December 31, 2006 year-end balance in the revenue Deficiency Deferral Account in the amount of $42,626,420;
- The permanent rates effective January 1, 2008 for RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF, and ILF rate classes as well as Firm Transportation, summer Interruptible Transportation, and winter Interruptible Transportation rates as proposed in the Revised Application, effective January 1, 2008 for rates; and
- The forecast Cost of Service and Revenues for 2008 as filed in the Revised Application
- Allowable capital expenditures for 2008, other than those expenditures that require a CPCN, which will be reviewed in separate regulatory processes, as included in the Revised Application.

2.8 2008 Settlement Update of 2009 Revenue Requirements

On October 8, 2008, FEVI filed its 2008 Settlement Update filing in accordance with the FEVI Extended Settlement Agreement. Further, on October 17, 2008, FEVI filed an amendment and on December 3, 2008, FEVI filed its Revised Application supplemented by a filing on December 9, 2008. In the application, FEVI requested Commission approval for the following:

- Rates set forth to be effective January 1, 2009;
- Forecast Cost of Service (Revenue Requirements) for 2009;
- Allowable capital expenditures forecast for 2009, other than those expenditures that require a CPCN;
- Forecast revenue proposed for 2009;
- The December 31, 2007 year- end balance in the RDDA;
- Proposals to deal with the event that the pipeline project to Whistler ;
- Deferral account treatment of incremental costs associated with the implementation of IFRS Implementation, to be amortized beginning 2011; and
- Deferral account treatment of incremental costs associated Olympic and Paralympic Games Security, to be amortized beginning 2011.

By Order No. G-192-08, dated December 12, 2008, the Commission approved the following:

- The December 31, 2007 year-end balance in the Revenue Deficiency Deferral Account in the amount of $27,907,609;
- The permanent rates, effective January 1, 2009, for RGS, AGS, SCS-1, SCS-2, LCS-1, LCS-2, LCS-3, LCS-13, HLF, and ILF rates classes as proposed in Schedules 28D and 28E of the Updated Application. The Commission also approves permanent rates effective January 1, 2009 for Firm Transportation ("FT"), summer Interruptible Transportation ("IT"), and winter IT rates as proposed in Schedule 28F of the October 17 filing;
- The permanent rate for Firm Transportation to Whistler as calculated in the December 9 filing;
- The forecast Cost of Service and Revenues for 2009 as filed in the Oct 17 filing;
- Proposals to deal with the event that the pipeline project to Whistler is energized in 2009 and conversion of the Whistler system is complete such that natural gas is flowing prior to year end as contained in Section 2 of the Application;
- The recording of the incremental costs in the requested IFRS deferral account and the Olympic and Paralympic Games deferral account; and
- To track the monthly activity in RDDA and when the account has reached an actual zero balance, FEVI was to file, within 30 days, a proposal to the Commission for the disposition of the surplus collected along with recommended rate changes.

2.9 2010-2011 Revenue Requirements

On June 29, 2009, FEVI filed an application for approval of its 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account balance as at December 31, 2008. The Application was filed, pursuant to sections 59 to 61 and 89 of the Act and section 2.2 of the Special Direction issued pursuant to Order in Council 1510. FEVI requested no change in the 2009 sales service rates and a reduction to rates for firm transportation service, other than those customers who have specified rates in their transportation service agreements, in the amount of 4.75 percent.

Notable in the application were the significant changes taking place in the external operating environment, including:

- Evolving energy and environmental policies;
- The changing expectations of customers, regulators, and other stakeholders;
- FEI's level of competitiveness as an energy provider; and
- Changing economic and demographic realities.

A Negotiated Settlement Process commenced on October 29, 2009 and concluded on November 5, 2009, and on November 26, 2009, the Commission issued Order No. G-140-09 approving the 2010-2011 FEVI NSA including, among other things, the following:

- User per customer rates as applied for;
- EEC Funding for 2010:
    - Reallocate from residential and commercial EEC programs an additional $0.4 million to low income and rental housing programs (bringing the total of for those programs to $0.6 million for 2010);
    - Innovative technologies funding be $0.478 million, and will be managed as a separate segment of the overall portfolio and have a weighted average Total Resource Cost of 1.0 or more;
- EEC Funding for 2011:
    - Residential and commercial program funding for 2011 be $4.726 million;
    - Reallocate from residential and commercial EEC programs an additional $0.4 million to low income and rental housing programs (bringing the total of for those programs to $0.6 million for 2011);
    - Innovative technologies funding be $0.956 million, and will be managed as a separate segment of the overall portfolio and have a weighted average Total Resource Cost of 1.0 or more and FEVI will report on innovative technology programs as part of the annual EEC report;
- Alternative Energy Solutions (now referred to as Thermal Energy Solutions or "Thermal Energy"):

    - Thermal Energy mean Geo-exchange, Solar-thermal and District Energy Systems;
    - FEI will be pursuing Thermal Energy projects within the FEVI service area and costs incurred by FEI will not be recovered in FEVI's natural gas service rates but those costs will be directly charged to the FEI New Energy Solutions Deferral Account;
- Natural Gas Vehicles ("NGV"):
    - Service Rate Schedule was approved;
    - NGV Grants will be accounted for on a net-of-tax basis in a deferral account and amortized over a five year term;
    - Marketing costs in support of NGV that are included in the Application are appropriately included in the 2010 and 2011 cost of service;
- CPCN Threshold to remain at $5 million;
- Category A Capital be $188,000 for 2010 and $154,000 for 2011;
- Category C Capital be $4.4 million in 2010 and $4.1 million in 2011;
- Reduction in O&M from the amount requested in the Application by $0.874 million in 2010 and by $0.947 million in 2011, resulting:
    - Reduction to the Shared Services costs from FEI in the amount of $0.339 million in 2010 and $0.491 million in 2011 ;
    - Reduction to Corporate Services costs from FHI in the amount of $0.535 million in 2010 and $0.54 million in 2011;
- Total depreciation expense of $21.8 million in 2010 and $26.0 million in 2011;
- An estimate of net removal costs of $0.343 million in 2010 and $0.344 million in 2011 be included in the cost of service, with the variance between actual realized net removal costs and the estimated amounts be recorded in a new deferral account, entitled "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two-year period will be recovered from or returned to customers in 2012;
- Change in the Overheads Capitalized rate to 14 percent of Gross O&M for 2010 and 2011;
- Defer the 2010 revenue requirements impact of IFRS to be reflected in the revenue requirements in 2011 up to a maximum of $2.0 million with amounts, if any, over $2.0 million be deferred and recovered in rates after 2011;
- The forecast balance in the 2009 RSA of $2.962 million be amortized equally over 2010 and 2011 to all customers, other than the VIGJV and Squamish as follows:
    - $2.677 million to Core Market
    - $0.246 million to BC Hydro
    - $0.039 million to FEW

- Any variance between the forecast and actual 2009 RSA balance will be captured in the Rate Stabilization Deferral Account ("RSDA")

- Variance between forecast cost of service and actual cost of service, other than O&M, are items that will be "trued up to actual" as per the Special Direction. The allowed ROE will be adjusted to that approved which will apply to actual rate base. The RSDA will be established to record:
    - Differences in 2010 and 2011 between the net revenue received and the actual "trued-up" cost of service, excluding O&M variances from forecast; and
    - Any accumulated revenue deficiency in the RDDA after December 31, 2009
- Any balance in the RSDA will be amortized into the cost of service after 2011. How any balance in the RSDA will be allocated among customer classes and the period over which any balance in the RSDA will be amortized into cost of service will be deferred to a future proceeding.
- Rates for transportation customers, effective January 1, 2010 (other than those that have specified rates set out in their contracts (VIGJV and Squamish) are;
    - BC Hydro: Firm Transportation Rate $0.830 per GJ; Summer Interruptible Rate $0.830 per GJ; and Winter Interruptible Rate $1.1330 per GJ;
    - FEW: Firm Transportation Rate $0.930 per GJ;
    - These rates are subject to changes flowing from the Commission's impending decision on the FEU 2009 ROE and Capital Structure Application by a formula of for every 1 basis point difference in the approved ROE as compared to the current ROE of 9.17 percent will cause the firm and interruptible rates to change in the same direction by 0.034 cents per GJ rounded to the nearest tenth of a cent.

As part of reaching the Agreement with the Parties and upon acceptance of the Agreement by the Commission, FEVI agreed to withdraw its requests related to NGV and Biogas as follows:

- NGV:
    - Rate Schedule 6C NGV Compression and Refueling Service and Rate Schedule 6A NGV Refueling Service;
    - The Compression Service Test;
    - NGV non-rate base deferral account; and
    - The Parties agreed that the withdrawal of the requests was done without prejudice to FEVI's right to bring forward similar requests in 2010, 2011 or in the future; acknowledged that FEVI intended to develop this area of business; and FEVI anticipated bringing forward applications on NGV projects on a case-by-case basis.
- Biogas:
    - All requests related to Biogas; and

- the Parties agreed that FEVI would bring forward an application for Biogas (the "Biogas Application") during the test period that would:
  - Address the economic assessment model;
  - Provide Biogas rates (including green rate, transportation rate, etc.);
  - Provide recovery of costs associated with providing Biogas service; and
  - FEVI may include any Biogas Projects under development at that time and that FEVI may apply for Commission approval of individual Biogas Projects at any time, either prior to the Biogas Application or afterward.

Further, on December 16, 2009, the Commission issued its Decision and Order No. G-158-09 on the FEU 2009 ROE and Capital Structure Application setting the ROE for FEI (the benchmark) to 9.50 percent effective July 1, 2009, and determined that FEVI should be allowed a 50 basis points premium over FEI's ROE. FEVI's equity ratio remained at 40 percent, and its ROE was set at 10.00 percent, effective January 10, 2010.

2.10 Summary

As discussed above, FEVI has met the expectations of its regulatory commitments through the settlement periods. Consequently, the settlement agreements coupled with annual reviews and settlement updates have served their purpose by aligning the interest of FEI's customers, stakeholders, and shareholder.

3 FORTISBC ENERGY (WHISTLER) INC.

Until 2009, FEW owned and operated a propane gas distribution system in Whistler. The original propane distribution system was established in 1980.

Construction of the natural gas pipeline lateral (the "Pipeline Project") connecting the Resort Municipality of Whistler ("RMOW") to the transmission system of FEVI was completed in April 2009. Throughout the period from May to August, 2009, the piped propane system and customer appliances were converted to natural gas. The distribution system now consists of an underground distribution piping system and IP/DP station at Function Junction in Whistler. Natural gas is received at the IP/DP station from the Intermediate Pressure Line of FEVI which interconnects with the FEVI transmission line at FEVI's Squamish station.

What follows, is a brief synopsis of the FEW's regulatory history by reviewing FEW's application to convert Whistler from propane to natural gas, followed by its applications and Commission decisions for each year since 2006.

3.1 2005 CPCN Application to Convert Whistler from Propane to Natural Gas

On December 16, 2005, FEW filed an application with the Commission that included requests for the following:

- A CPCN to convert the FEW system from propane to natural gas;
- Approval to enter into a long-term natural gas transportation agreement with FEVI;
- Approval to make a capital contribution to FEVI for the construction of an intermediate pressure pipeline to connect Whistler with the FEVI high pressure transmission system at Squamish and to add that contribution to rate base;
- Approval to amortize the net book value of the propane facilities; and
- Approval to recover the pipeline study costs incurred prior to 2004.

In Order No. C-3-06, dated June 26, 2006, the Commission granted the following:

- A CPCN to convert FEW's system to natural gas;
- Additions to FEW's rate base subject to cost risk-sharing mechanisms;
- A Transportation Services Agreement and a Contribution Agreement between FEVI and FEW;
- Permission for FEW to discontinue propane service to Whistler when natural gas service is fully in place; and
- Commencing September 30, 2006, FEW was to file quarterly progress reports on the schedule and costs of the Whistler conversion, followed by a final completion report.

3.2 2007 Rates

On December 7, 2006, FEW applied to the Commission to roll over existing rates and clarify accounting treatment for certain deferral accounts. By Order No. G-172-06, dated December 21, 2006 the Commission approved the continuation of:

- Existing rates and the Rate Rider 'A' adjustment mechanism; and
- The recording of variances in the Interest Rate Differential deferral account, Property Tax deferral account, Sales Margin Differential deferral account and Deferred Return on Equity variance account.

3.3 2008 Rates

On November 16, 2007, FEW applied to the Commission for Deferral Account Continuity for 2008. At the time, FEW expected the natural gas pipeline lateral connecting the RMOW to the

FEVI transmission system and conversion of its system to natural gas to be completed in mid-2009. FEW reiterated its intent to file a two-year revenue requirements application for 2009 and 2010 that would address appropriate ROE, capital structure, rates and deferral account disposition. The Commission approved FEW's Deferral Account Continuity request in Order No. G-146-07, dated November 29, 2007, as well as the establishment of a non-rate base deferral account to record consulting costs incurred regarding FEW's capital structure and ROE.

3.4 2009 Revenue Requirements and Rates and Return on Equity and Capital Structure Application

On October 3, 2008, FEW filed its 2009 Revenue Requirements and Rates and Return on Equity and Capital Structure Application. An update to the Application was filed on November 21, 2008 to address a number of matters. On April 7, 2009, the Commission rendered its Decision on the Application and issued Order No. G-35-09. In the Decision the Commission approved a number of deferral accounts such as Margin Deferral, Interest Deferral Account, and Property Tax Deferral. The Commission also approved other deferrals related to the CPCN to convert Whistler from a propane system to natural gas; and other one-time deferrals were also approved. FEW did file a Reconsideration of this Decision that was limited in nature and based on a mistake of fact that $1.076 million dollars of conversion costs represented the tax benefit of a carry back that was not returned to customers. The Decision on this particular point would have denied FEW from proper recovery of $1.076 million of conversion costs. Commission Order No. G-52-09 dated May 15, 2009 approved the request in the Reconsideration by FEW.

3.5 2010-2011 Revenue Requirements and Rates Application

On November 9, 2009, FEW applied for approval of its 2010-2011 Revenue Requirements and Rates Application to amend its rates, effective January 1, 2010, pursuant to sections 58, 60, 61 and 89 of the Act. Among other things, the Application sought:

- To unbundle tariff rates, resulting in a decrease of approximately 13.5 percent of total tariff revenue in 2010 as compared to 2009, and a further 2.9 percent decrease in 2011;
- Inclusion in FEW's rate base of the costs of the Whistler Conversion in the amount of $11.87 million ($5.86 million in excess of the maximum Conversion costs approved in Orders No. C-3-06 and C-53-06);
- Amendments to certain Pipeline Project costs; and
- Changes to certain accounting treatments to harmonize the FEW Tariff and Special Rates Schedules with FEI and FEVI.

On December 16, 2009, the Commission issued its Decision and Order No. G-158-09 on the FEU 2009 ROE and Capital Structure Application setting the ROE for FEI (the benchmark) to 9.50 percent effective July 1, 2009, and determined that FEW should be allowed a 50 basis points premium over FEI's ROE. FEW's equity ratio remained at 40 percent, and its ROE was set at 10.00 percent, effective January 1, 2010.

On September 1, 2010, the Commission issued Order No. G-138-10, set rates as interim, pending the finalization of the Pipeline Project costs. Order No. G-138-10 approved, among other things, the following:

- An unbundled rate decrease of approximately 13.5 percent in 2010 and a further 2.9 percent in 2011, adjusted to reflect any Commission-approved quarterly adjustments to the Gas Cost Recovery Charge and ROE adjustments required under Order No. G-158-09, and directed FEW to:
  - Adopt IFRS for regulatory purposes as the same time as such standards have been adopted for financial accounting purposes;
  - Establish separate sub-accounts to track Harmonized Sales Tax adjustments related to O&M and capital items;
  - Apply an overheads capitalization rate of 14 percent in 2010 and 2011;
  - Record an estimate of actual removal costs incurred in 2010 and 2011 rather than a provision for negative salvage; and
  - Include in rate base for recovery from customers $11.03 million in costs related to the Conversion Project.
- Amendments to certain Pipeline Project costs as requested in the Application;
- Calculate revised interim rates based on the directives in Order No. G-158-09;
- Revised interim rates to remain in effect until all Pipeline Project costs are finalized or until addressed by further order of the Commission; and
- Difference, if any, between the 2010 interim and permanent delivery rates that are determined following final disposition of the Pipeline Project costs or upon issuance of a further order making rates permanent, those amounts are subject to refund/recovery, with interest at the average prime rate of FEW's principal bank, as soon as practicable.

As a result ongoing negotiations with the Pipeline contractor in trying to reach resolution of the final Pipeline Project costs, FEW anticipates a further six or more months may be required before the final Pipeline Project costs are know. On April 14, 2011, FEW applied for approval of the interim rates on a permanent basis, and proposed the creation of a rate-base deferral account, entitled "Pipeline Contribution Cost Variance Deferral Account" to record any differences between:

a) the cost of service from April of 2009 to December 31, 2011 associated with the Pipeline Contribution that is included in the calculation of the interim rates ($17.034 million), and

b) the cost of service from April of 2009 to December 31, 2011 associated with the final Pipeline Contribution amount.

FEW also proposed to provide as part of its 2012-2013 revenue requirements application an estimate of the final contribution amount and that the forecast balance in the Pipeline

Contribution Cost Variance Deferral Account (the Forecast Balance) be returned to customers in 2012 with the difference, if any, between that Forecast Balance returned to customers in 2012 rates, and the final actual balance in that account once the final Pipeline contribution is known, remain recorded in that account for disposition in a future revenue requirements application. A decision on this application had not yet been rendered at the time of filing its 2012-2013 revenue requirements application.

3.1 Summary

Apart from a reduction in overall rates as a result of the conversion from propane to natural gas, there have been several other benefits that Whistler customers have enjoyed, these include:

- Significantly improved system safety and reliability;
- Reduction in Greenhouse Gas Emissions;
- Contribution towards the RMOW's comprehensive community sustainability plan;
- Access to commodity-related benefits of being a part of the gas supply portfolio for FEI, which is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs; and
- Access to necessary resources, expertise and training in all areas affecting gas distribution facilities.

Appendix B-3

KEY OPERATING FACTS

Appendix B-3
Key Operating Facts 2003-2010

FEI
Annual Report Statistics
2003-2010

	2003	2004	2005	2006	2007	2008	2009	2010
Customers:								
12 Month Average Residential Customers	692,297	701,290	712,427	722,865	735,263	743,756	749,999	756,051
12 Month Average Commercial Customers	76,377	76,054	76,880	77,511	78,810	79,538	80,373	80,589
12 Month Average Industrial Customers	513	482	428	383	334	306	294	268
12 Month Average Transportation Customers	1,389	1,595	1,819	1,947	1,984	2,066	2,058	2,084
12 Month Average NGV Customers	48	40	39	37	36	30	27	25
Total Average Customers	**770,624**	**779,461**	**791,593**	**802,743**	**816,427**	**825,696**	**832,751**	**839,017**
Total Year End Customers	775,516	787,020	799,365	809,559	822,598	831,845	836,918	843,846
Gas Deliveries (Actual):								
Residential Gas Delivery (TJ)	68,361	66,026	68,962	68,240	70,638	68,841	69,999	70,041
Commercial Gas Delivery (TJ)	38,418	37,770	38,422	37,767	39,581	39,667	40,716	40,013
Industrial Gas Delivery (TJ)	5,829	5,117	4,547	4,072	3,692	3,408	3,168	2,660
Transportation Gas Delivery (TJ)	96,719	101,697	99,923	98,708	100,791	98,081	86,856	88,336
NGV Gas Delivery (TJ)	241	318	186	135	117	94	83	61
Total Gas Deliveries	**209,568**	**210,928**	**212,040**	**208,922**	**214,819**	**210,091**	**200,822**	**201,111**
Cost of Gas (Normalized)								
Average Cost of Gas Sold ($/GJ)	$ 7.03	$ 7.35	$ 8.45	$ 9.13	$ 8.45	$ 8.91	$ 7.18	$ 6.76
O&M:								
Approved CPI (BC)	1.7%	1.7%	2.0%	2.2%	2.0%	2.1%	2.1%	1.9%
Gross O&M Decision (adj for Pension/Insurance)	$ 176,915	$ 192,390	$ 190,586	$ 196,919	$ 199,462	$ 200,052	$ 203,994	$ 210,569
Gross O&M Actual	168,627	176,951	171,602	180,026	179,808	186,479	192,729	207,013
Capitalization Allowed	-25,207	-26,009	-26,335	-27,243	-27,535	-27,684	-28,241	-29,019
Vehicle Lease	-1,918	-1,900	-1,911	-1,872	-2,008	-1,988	-1,804	-
Coastal Lease	-	-4,505	-	-	-	-	-	-
Fort Nelson Allocation	-539	-611	-646	-688	-701	-599	-658	-679
Total Net O&M	**$ 140,963**	**$ 143,926**	**$ 142,710**	**$ 150,223**	**$ 149,564**	**$ 156,208**	**$ 162,026**	**$ 177,315**
Headcount								
Average Full Time Equivalent (FTE)	1,190	1,089	1,092	1,062	1,087	1,127	1,241	1,165
Distribution Fast Facts:								
Outages caused by Third Party	1,459	1,491	1,457	1,434	1,545	1,574	1,322	1,253
Gas Odour Calls	21,347	21,861	20,443	23,497	22,792	20,335	18,620	18,710
CO Calls	1,512	1,405	1,418	1,224	1,573	1,583	1,350	1,660
Fire Calls	712	610	733	882	996	973	780	690
Meter Recalls	45,142	45,185	45,448	28,457	32,175	33,275	45,125	61,560
Locates	324	2,523	1,837	1,739	2,378	3,153	2,900	2,550
Calls to BC 1 Call	46,500	46,500	46,500	46,500	58,000	41,000	54,642	59,050
Lock Offs - Interior	15,845	12,973	10,582	8,949	9,567	10,623	10,200	10,075
Lock Offs - Coastal	905	1,807	1,414	1,105	1,657	1,628	1,829	2,040
Unlocks - Interior	15,006	8,767	11,093	9,478	9,936	10,431	9,300	9,600
Unlocks - Coastal	30,521	24,210	22,118	20,326	23,888	22,530	21,800	19,520
Service Lines (Risers)	713,700	713,700	713,700	713,700	743,928	735,891	753,321	761,677
# of Main Valves	9,438	9,438	9,438	9,438	9,425	9,024	8,808	8,951
# of Service Valves	16,994	16,994	16,994	16,994	16,960	16,735	17,485	17,681
Regulator Stations	416	416	416	416	416	390	389	413
Line Heaters	200	200	200	200	200	245	228	233
Pipeline Stats:								
Total TP Pipe (KM's)	2,415	2,415	2,415	2,415	2,418	2,418	2,319	2,324
Total IP (KM's)	350	350	350	350	516	511	502	504
Total DP Service Pipe (KM's)	16,700	16,964	17,205	17,455	17,655	17,872	18,463	17,196
Total DP Main Pipe (KM's)	18,300	18,651	19,018	19,377	19,730	20,123	18,766	19,449
Total LP Pipe (KM's)	100	100	100	100	58	24	0.5	-
Total Pipeline	**37,865**	**38,480**	**39,088**	**39,697**	**40,377**	**40,948**	**40,051**	**39,473**
System Outages:								
Outages	1,532	1,566	2,291	2,414	2,935	2,638	1,975	2,333
Customers Affected	2,857	3,912	3,981	2,691	3,631	2,772	2,674	3,613
System Leaks:								
Transmission Pipeline Leaks	3	3	3	1	1	2	-	-
Distribution Pipeline Leaks	134	150	120	71	87	57	60	140
Emergency Response Time (minutes)	22:00	21:36	21:42	21:24	20:36	20:42	22:41	22:30
Service Quality Indicators:								
Emergency Calls Answered in 30 seconds	96.3%	97.9%	99.0%	98.7%	98.4%	98.3%	98.3%	99.2%
% of Transportation Customer Bills Accurate	99.8%	96.6%	99.9%	99.9%	99.5%	94.3%	96.0%	99.9%
Customer Satisfaction	73.9%	73.9%	77.2%	77.9%	79.3%	79.7%	80.1%	80.0%
Customer Complaints to BCUC	101	191	100	145	130	90	58	26
Miscellaneous:								
Rate Base, Mid-Year	$ 2,249,535	$ 2,305,591	$ 2,408,090	$ 2,442,636	$ 2,425,545	$ 2,471,877	$ 2,460,772	$ 2,893,659
Allowed Return	9.420%	9.150%	9.03%	8.80%	8.37%	8.62%	8.47%	9.50%

FEVI
Annual Report Statistics
2003-2010

	2003	2004	2005	2006	2007	2008	2009	2010
Customers:								
Average Residential Customers	66,703	69,957	73,294	76,554	80,332	83,873	86,929	89,496
Average Commercial Customers	8,549	8,658	8,695	8,767	8,970	9,133	9,309	9,424
Average Industrial Customers	3	3	3	3	3	3	4	4
Total Average Customers	**75,255**	**78,618**	**81,992**	**85,324**	**89,305**	**93,009**	**96,242**	**98,924**
Residential Customers	67,981	71,932	76,053	78,453	82,210	85,536	88,321	90,671
Commercial Customers	8,552	8,764	8,963	8,908	9,032	9,234	9,383	9,465
Industrial Customers	3	3	3	3	3	3	4	4
Total Customers Year End	**76,536**	**80,699**	**85,019**	**87,364**	**91,245**	**94,773**	**97,708**	**100,140**
Gas Deliveries								
Residential Gas Delivery (GJ)	3,959,821	3,830,413	4,161,949	4,544,713	4,675,253	5,033,583	4,912,705	4,547,786
Commercial Gas Delivery (GJ)	7,211,784	6,971,935	7,310,707	7,265,630	7,619,542	7,637,380	7,396,654	6,943,608
Transportation Gas Delivery (GJ)	21,169,075	21,536,486	22,145,616	16,333,996	23,302,318	22,342,055	18,868,782	19,526,346
Total Gas Deliveries	**32,340,680**	**32,338,834**	**33,618,272**	**28,144,339**	**35,597,113**	**35,013,018**	**31,178,141**	**31,017,740**
Gas Cost								
Average Cost of Gas Sold ($/GJ)	$ 7.04	$ 6.96	$ 8.22	$ 8.42	$ 8.21	$ 8.46	$ 8.07	$ 6.47
Royalty Revenue	$ 34,058,747	$ 36,125,648	$ 46,722,424	$ 36,326,142	$ 35,063,082	$ 43,141,851	$ 21,891,155	$ 17,215,110
O&M:								
Gross O&M Actual	$ 31,375,890	$ 30,301,643	$ 28,417,324	$ 25,752,383	$ 24,748,053	$ 26,022,171	$ 26,758,569	$ 30,460,661
Gross O&M Allowed	31,555,833	32,301,500	32,397,300	29,117,690	30,006,764	30,607,000	31,456,000	31,231,000
Capitalization Allowed	-5,208,310	-5,028,115	-4,626,492	-4,695,000	-4,839,000	-4,935,996	-5,032,960	-4,372,368
Total Net O&M	**$ 26,347,523**	**$ 27,273,385**	**$ 27,770,808**	**$ 24,422,690**	**$ 25,167,764**	**$ 25,671,004**	**$ 26,423,040**	**$ 26,858,632**
Headcount								
Average Full Time Equivalent (FTE)	205	168	155	119	102	97	97	101
Pipeline Stats:								
Pipeline Installed (Metres)	83,000	43,000	49,000	47,500	76,500	42,450	74,988	22,065
Total Plastic Pipeline (Metres)	2,682,681	2,720,781	2,764,683	2,810,196	2,864,539	2,917,572	2,942,248	2,960,530
Total Steel Pipeline (Metres)	181,364	181,364	181,384	181,384	183,710	183,710	232,810	232,810
Total HP Steel Pipeline (Metres)	762,234	762,234	762,234	762,257	767,191	767,191	767,191	767,709
Total MOPP Pipeline (Metres)	132,649	137,023	141,032	141,032	145,702	131,027	131,027	131,027
Total P. Sys Bet. Pipeline (Metres)	51,605	52,188	53,256	53,256	63,558	67,621	68,832	72,097
Total Pipeline	**3,810,533**	**3,853,590**	**3,902,589**	**3,948,125**	**4,024,700**	**4,067,121**	**4,142,108**	**4,164,173**
System Outages:								
Outages	124	159	187	245	290	282	189	188
Customers Affected	575	504	322	852	574	608	416	478
Maximum Customers Affected by an Outage	232	81	39	603	216	338	98	254
System Leaks:								
Leaks per km of Transmission Pipeline	0.029	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Leaks per km of Distribution Pipeline	0.0350	0.0100	0.0046	0.0051	0.0039	0.0028	0.0063	0.0224
Emergency Response Time (minutes)	22.8	17.4	19.9	15.2	16.6	16.2	19.1	18.9
Miscellaneous:								
Rate Base, Mid-Year	$ 437,203,975	$ 440,554,577	$ 452,604,849	$ 464,180,271	$ 478,699,400	$ 511,422,212	$ 532,925,299	$ 547,771,854
Allowed Return	9.92%	9.65%	9.53%	9.50%	9.07%	9.32%	9.59%	10.00%

FEW
Annual Report Statistics
2010

		2,010
Customers:		
12 Month Average Residential Customers		2,256
12 Month Average Commercial Customers		330
Total Average Customers		**2,586**
Total Year End Customers		2,592
Gas Deliveries (Actual):		
Residential Gas Delivery (GJ)		218,386
Commercial Gas Delivery (GJ)		534,809
Total Gas Deliveries		**753,195**
Cost of Gas (Normalized)		
Average Cost of Gas Sold ($/GJ)		7
O&M:		
Gross O&M Actual		772,638
Capitalization Allowed	-	118,806
Total Net O&M		**653,832**
Distribution Fast Facts:		
# of Main Valves		89
# of Service Valves		30
Pipeline Stats:		
Total DP Service Pipe (KM's)		30
Total DP Main Pipe (KM's)		96
Total Pipeline		**126**
Miscellaneous:		
Rate Base, Mid-Year	$	45,385,904
Allowed Return		10%

Appendix B-4

MUNICIPALITIES SERVED

FortisBC Energy Inc. - Municipalities Served

Lower Mainland Service Area:

Abbotsford	Mission
Anmore	New Westminster
Belcarra	North Vancouver City
Burnaby	North Vancouver Dist.
Chilliwack	Pitt Meadows
Coquitlam	Port Coquitlam
Delta	Port Moody
Harrison Hot Springs	Richmond
Hope	Squamish
Kent	Surrey
Langley City	Vancouver
Langley District	West Vancouver
Maple Ridge	White Rock
Matsqui	

Columbia Service Area:

Cranbrook	Jaffray
Creston	Kimberley
Elkford	Sparwood
Fernie	Yahk
Galloway	

Fort Nelson Service Area:

Fort Nelson
Prophet River

Inland Service Area:

Armstrong	Montrose
Ashcroft	Naramata
Bear Lake	Nelson
Cache Creek	Okanagan Falls
Castlegar	Oliver
Chase	100 Mile House
Chetwynd	108 Mile House
Christina Lake	150 Mile House
Clinton	Osoyoos
Coldstream	Oyama
Collettville	Peachland
Craigmont	Penticton
Falkland	Prince George
Ferguson Lake	Princeton
Fruitvale	Quesnel
Gibralter Mines	Revelstoke
Grand Forks	Robson
Greenlake	Rossland
Greenwood	Salmo
Hedley	Salmon Arm
Hixon	Savona
Honeymoon Creek	Shelley
Hudson's Hope	Sorrento
Kamloops	Spallumcheen
Kelowna	Summerland
Keremeos	Trail
Lac La Hache	Vernon
Lakeview Heights	Warfield
Logan Lake	Westbank
Lumby	Westwold
MacKenzie	Williams Lake
Merritt	Winfield
Midway	Woodsdale

FortisBC Energy (Vancouver Island) Inc. - Municipalities Served

Black Creek	Lazo
Campbell River	Merville
Cedar	Metchosin
Central Saanich	Mill Bay
Chemainus	Nanaimo
Cobble Hill	Nanoose Bay
Colwood	North Saanich
Comox	Oak Bay
Coombs	Parksville
Courtenay	Port Alberni
Cowichan Bay	Powell River
Crofton	Qualicum Beach
Cumberland	Roberts Creek
Duncan	Royston
Errington	Saanich
Esquimalt	Sechelt
Gibsons	Shawnigan Lake
Halfmoon Bay	Sidney
Highlands	Sooke
Ladysmith	Victoria
Langford	View Royal
Lantzville	

Appendix B-5

STATUS OF PAST DIRECTIVES

No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
G-141-09 – FEI (then TGI) 2010-2011 Revenue Requirements Negotiated Settlement Agreement				
1.	Appendix A, Page 10, Section 13	**Alternative Energy Services:** TGI will capture costs and revenue on a project specific basis and will report on AES projects as part of the next Revenue Requirements application.	Included in this RRA.	Appendix G
2.	Appendix A, Page 13, Section 22	**Depreciation Study:** TGI will undertake an updated depreciation study to be included as part of TGI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.	Depreciation Study completed, including negative salvage discussion.	Section 5.4 and Appendix E-1
3.	Appendix A, Pages 13 and 14, Section 23	**Negative Salvage:** Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.	Removal cost variances have been collected in the Removal Cost Deferral Account and are being recovered from customers in 2012 and 2013. Negative salvage discussion included in Depreciation Study; Asset Removal Costs and Asset Retirement Obligations report also filed.	Section 5.4 and Appendix E-2
4.	Appendix A, Page 14, Section 24	**Unrecovered Losses:** The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this agreement. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.	Analysis of unrecovered losses and disposition included in Loss Analysis Report.	Section 5.4 and Appendix E-3

No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
G-140-09 – FEVI (then TGVI) 2010-2011 Revenue Requirements Negotiated Settlement Agreement				
5.	Appendix A, Page 14, Section 16	**Depreciation Study:** The Parties agree that TGVI will undertake an updated depreciation study to be included as part of TGVI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGVI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.	Depreciation Study completed, including negative salvage discussion.	Section 5.4 and Appendix E-1
6.	Appendix A, Page 15, Section 17	**Negative Salvage:** TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.	Removal cost variances have been collected in the Removal Cost Deferral Account and are being recovered from customers in 2012 and 2013. Negative salvage discussion included in Depreciation Study; Asset Removal Costs and Asset Retirement Obligations report also filed.	Section 5.4 and Appendix E-2
7.	Appendix A, Page 15, Section 18	**Unrecovered Losses:** TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.	Analysis of unrecovered losses and disposition included in Loss Analysis Report.	Section 5.4 and Appendix E-3
8.	Appendix A, Page 17, Section 22	**RSDA Balance:** The Parties agree that any balance in the RSDA will be amortized into the cost of service after 2011. However, the Parties agree that the following issues will be deferred to a future proceeding: (a) how any balance in the RSDA will be allocated among customer classes; and (b) the period over which any balance in the RSDA will be amortized into the cost of service.	The future proceeding during which this issue will be addressed is the Amalgamation and Rate Design Application to be filed Q3 2011.	N/A

No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
G-158-09 – FEU (then Terasen Utilities) 2009 ROE and Capital Structure Decision				
9.	Directive No. 7	7. TGVI and TGW are to file in their respective next revenue requirement applications evidence on the equity component that best reflects their respective long-term business risks.	FEVI and FEW are requesting leave to defer filing evidence for theie capital structures until the Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011.	Section 5.7.2
G-138-10 – FEW (then TGW) 2010-2011 Revenue Requirements Decision				
10.	Appendix A, Page 6, Section 2.1.2	**RSAM:** The Commission Panel agrees that aligning TGW's methodology with that of TGI is beneficial. The creation of the RSAM account to replace the Sales Margin Differential Account is approved. The commencement of amortization of the RSAM account over three years commencing in 2012 is also approved. The Commission Panel directs TGW to provide details of any balance accumulated in the RSAM deferral account during 2010 and 2011 in its next revenue requirements application, and to propose a method for recovery from, or refund to, customers at that time.	Amounts accumulated in 2010 and proposed amortization period included in Rate Base Deferrals section of the Application.	Section 6.3
11.	Appendix A, Page 7, Section 2.1.3	**DSM/EEC:** The Commission Panel shares RMOW's concern about the lack of DSM initiatives in TGW's Application, and directs TGW to develop plans for DSM programs, consistent with British Columbia's energy objectives, in its next revenue requirements application.	EEC programs will be offered in Whistler; details included in the EEC Report	Appendix K

No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
12.	Appendix A, Page 9, Section 2.4	**Tax Variance Deferral Account:** The Commission Panel considers that the proposal to use a Tax Variance Deferral Account is an appropriate mechanism for the regulatory treatment of taxes. The Commission Panel agrees with the comments of BCOAPO concerning separation of operating and capital adjustments, and for those reasons directs TGW to establish separate sub-accounts to specifically track HST adjustments related to O&M and capital items and to provide this information with future revenue requirements applications. TGW is also directed to provide details of any balance accumulated in the Tax Variance Deferral Account during 2010 and 2011 and to propose a method for recovery from or refund to customers in its next revenue requirements application.	The Report "Harmonized Sales Tax Impacts on the 2010-2011 Revenue Requirements of the Terasen Utilities" was filed on September 27, 2010 indicating that, net of implementation costs, there were no amounts to be returned to customers. The amount was approved by Commission Letter L-96-10 (see Item 17 below)	N/A
13.	Appendix A, Page 10, Section 2.5.1	**IFRS:** The Commission Panel considers that the use of deferrals accounts is an appropriate mechanism for regulatory purposes to account for the transitional and ongoing impacts of the conversion of financial accounting standards to IFRS as described by TGW. TGW is directed to provide a report containing the details, with descriptions and explanations, of the amounts transferred to the new deferral accounts. The report is to be provided to the Commission within 60 days of the effective date of TGW's adoption of IFRS. TGW is further directed to provide details of any balance accumulated in the deferral accounts during 2010 and 2011 and to propose a method for recovery from or refund to customers where appropriate.	Due to the current uncertainty around the adoption of IFRS or US GAAP, the triggering event (adoption of IFRS) has not occurred. Any balances accumulated in the deferral accounts during 2010 and 2011 are included in the discussion of Rate Base Deferral Accounts.	Section 6.3
14.	Appendix A, Page 12, Section 2.7.2	**Overheads Capitalized:** The Commission Panel agrees that aligning TGW's overhead capitalization rate with that of TGI and TGVI is appropriate in order to achieve consistent accounting treatment amongst the related utilities. The Commission Panel directs TGW to apply an overhead capitalization rate of 14 percent in 2010 and 2011 in order to remain consistent with TGW's sister companies, TGI and TGVI. TGW is further directed to file a report with the Commission discussing overhead capitalization rates when the proposed accounting standards have been clarified and approved.	Due to the current uncertainty around the adoption of IFRS or US GAAP, the triggering event (clarification and approval of proposed accounting standards) has not occurred.	N/A

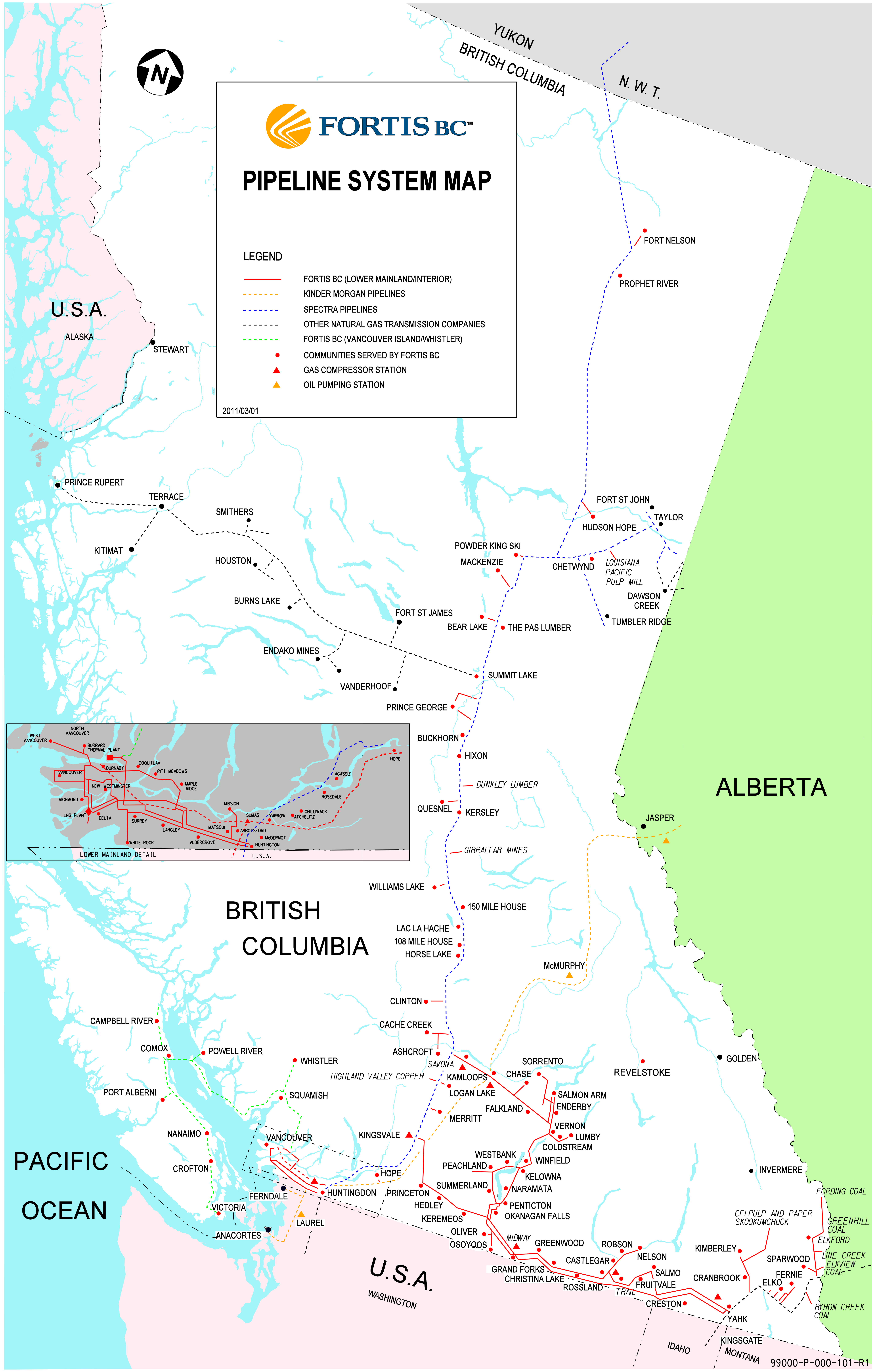
No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
15.	Appendix A, Page 13, Section 2.7.3	**Negative Salvage:** The Commission Panel takes note of the depreciation methods and policies adopted for TGI and TGVI as part of their respective Negotiated Settlement Agreements for 2010 and 2011. As noted in previous sections above, the Commission Panel generally agrees that it is beneficial to align TGW's policies and methodologies with those of TGI and TGVI where appropriate. Accordingly, the Commission Panel approves the depreciation policies and practices requested by TGW, for the forecast years 2010 and 2011, subject to the removal of the negative salvage provision from the composite depreciation rate as discussed above. Notwithstanding the foregoing approval, the Commission Panel is not convinced that the elimination of the negative salvage provision in the determination of the composite depreciation rate is appropriate on an ongoing basis. TGW is directed to include evidence with respect to negative salvage in future revenue requirement applications. The Commission Panel also suggests that consistent with the above comments concerning the alignment of TGW's policies and methodologies with those of TGI and TGVI, those utilities also include evidence with respect to negative salvage in their future revenue requirement applications.	Removal cost variances have been collected in the Removal Cost Deferral Account and are being recovered from customers in 2012 and 2013. Negative salvage discussion included in Depreciation Study; Asset Removal Costs and Asset Retirement Obligations report also filed.	Section 5.4 and Appendix E-2
16.	Appendix A, Page 14, Section 2.7.4	**IFRS Adoption:** The Commission Panel further directs TGW to adopt IFRS for regulatory purposes as at the same date it adopts IFRS for financial accounting purposes. In order to mitigate uncertainty surrounding accounting standards, TGW is directed, for regulatory purposes, to adopt only those accounting standards that have received final approval and are in force. TGW is directed to record any IFRS reconciliation adjustments in the IFRS Transitional Deferral Account. The Commission Panel directs TGW to provide, in its next revenue requirements application, details of any balances accumulated in the IFRS Transitional Deferral Account and to propose a method to recover from, or refund to, customers such balances at that time.	Whistler will be adopting US GAAP and not IFRS for financial accounting purposes. The accounting treatment to be adopted for regulatory accounting purposes is subject to a separate proceeding (FortisBC Utilities Application to Adopt US GAAP). Any balances accumulated in the deferral accounts during 2010 and 2011 are included in the discussion of Rate Base Deferral Accounts.	Section 6.3

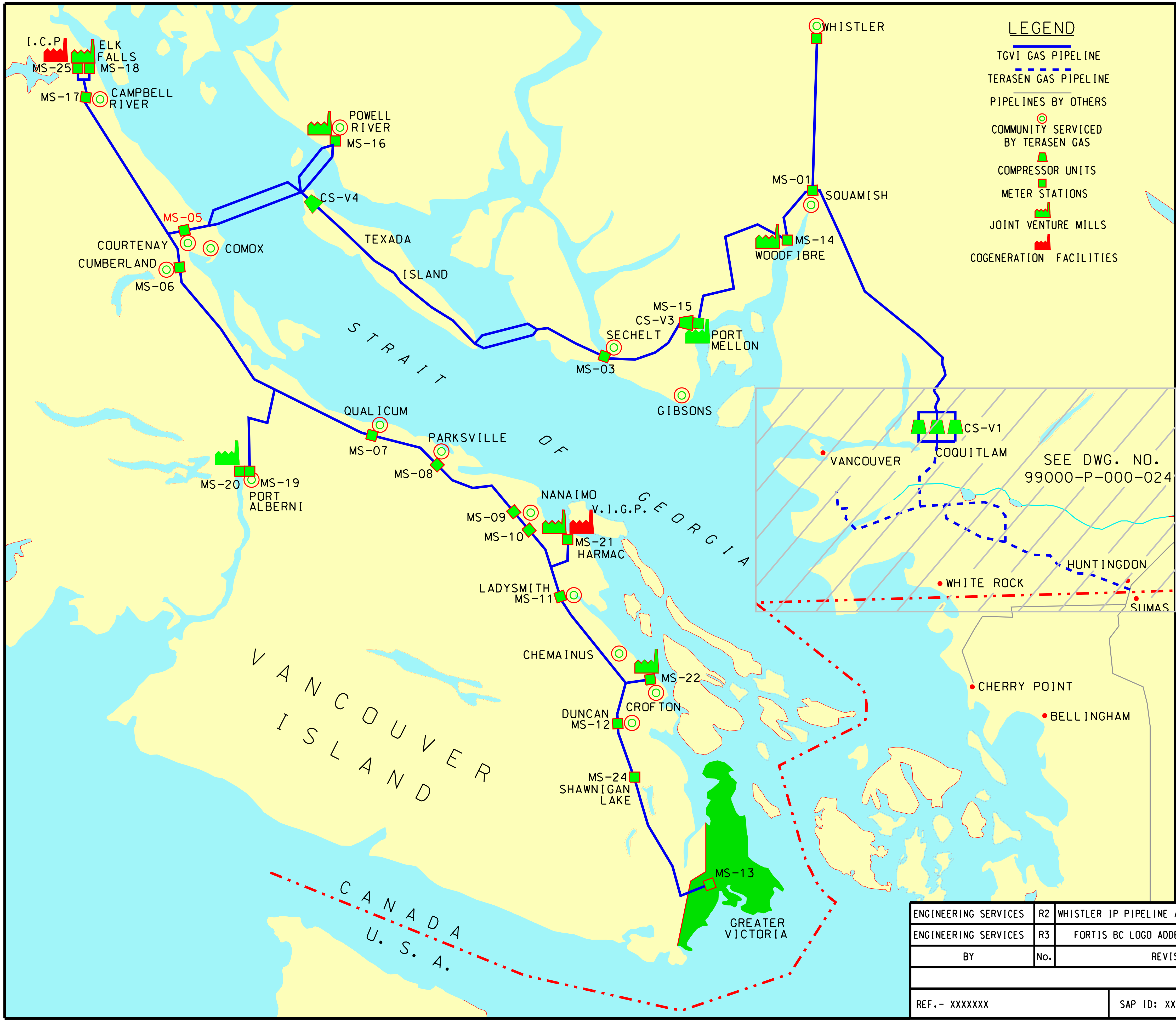
No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
L-96-10 – FEU (then Terasen Utilities) Harmonized Sales Tax Impacts in the 2010-2011 Revenue Requirements				
17.	Paragraph 4	**HST Impacts:** The Commission accepts that the final amounts to be returned to customers, and the potential recovery of any implementation costs, will be addressed as part of TGI, TGVI and TGW's 2012 Revenue Requirements Applications.	Included in this RRA Rate Base Deferral Accounts.	Section 6.3
G-194-10 – FEI (then TGI) Biomethane Decision				
18.	Page 58, Section 5.1	**Biomethane Variance Account (BVA) and O&M and Capital Costs:** Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA). Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs. This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided.	Included in this RRA.	Appendix J
19.	Page 59, Section 5.1 and Directive No. 10, bullet 3	**Biomethane Non-Rate Base Deferral Accounts:** As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well as a breakdown of the costs accumulated in the accounts by nature and dollar amount. Further, the Company is directed to present within its annual regulatory report to the Commission, the total value of each of these deferral accounts, net of any amortization. This is to be done each year until the remaining balance is $nil.	Included in this RRA.	Appendix J
C-1-11 – FEVI (then TGVI) Victoria Regional Office CPCN Decision				
20.	Appendix A, Page 13, Section 4.1	**TGVI Staffing Levels:** Commission Panel concludes that TGVI must undertake a detailed review and evaluation to assess the reasonableness of the number of staff and vehicles that TGVI reasonably needs to service the Victoria area. The detailed analysis of these matters which is requested in Section 5.1 could supplement an evaluation of the efficiency of TGVI's Victoria operations in its next revenue requirements proceeding.	TGVI Staffing Report filed February 28, 2011, CPCN C-6-11 granted to construct the Victoria Regional Facility as applied for.	N/A

No.	BCUC Order and Directive	Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
G-2-11 – FEU (then Terasen Utilities) Administration of the Basic Charge to a Daily Basis				
21.	Directive No. 4	4. Terasen Utilities should provide any cost savings due to the change in the administration and the invoicing of the Basic Charge from a monthly basis to a daily basis in the next Revenue Requirement Applications for the Terasen Utilities.	Included in this RRA.	Section 5.3.7
G-14-11 – FEU (then Terasen Utilities) Long Term Resource Plan Decision				
22.	Page 17	Terasen states that it plans to submit a request for on-going funding beyond 2011 for all Terasen Utilities in its 2012 Revenue Requirement Application.	Included in this RRA.	Section 5.3.8
G-27-11 – FEI (then TGI) Fort Nelson 2011 Revenue Requirements Application Decision				
23.	Directive No. 4	Approval of the proposed 2011 capital expenditures including $3,015,650 of capital costs (excluding AFUDC) related to the Muskwa River Crossing Project (Project)...the Commission approves the inclusion of Project costs...in 2011 ratebase...the total amortization/depreciation projected in this Application shall be recorded as a reduction to the carrying amount of the Project Assets in 2012. The Project assets shall not attract AFUDC after the projected in-service date [October 1, 2011] included in this Application.	Included in this RRA.	Section 7 Fort Nelson Schedule 43
24.	Appendix A, Page 11, Section 3.6.4	TGFN has not yet proposed a recovery strategy for the IFRS Transitional Deferral account as one will be proposed in the next revenue requirements application, consistent with TGI, when the accounting changeover is complete.	Due to the current uncertainty around the adoption of IFRS or US GAAP, the triggering event (accounting changeover completed) has not occurred. Any balances accumulated in the deferral accounts during 2010 and 2011 are included in the discussion of Rate Base Deferral Accounts	Section 6.3

Appendix B-6

SERVICE TERRITORY MAPS


FORTIS BC
PIPELINE SYSTEM MAP
LEGEND
FORTIS BC (LOWER MAINLAND/INTERIOR)
KINDER MORGAN PIPELINES
SPECTRA PIPELINES
OTHER NATURAL GAS TRANSMISSION COMPANIES
FORTIS BC (VANCOUVER ISLAND/WHISTLER)
COMMUNITIES SERVED BY FORTIS BC
GAS COMPRESSOR STATION
OIL PUMPING STATION
2011/03/01
YUKON
BRITISH COLUMBIA
N. W. T.
U.S.A.
ALASKA
STEWART
FORT NELSON
PROPHET RIVER
PRINCE RUPERT
TERRACE
SMITHERS
KITIMAT
HOUSTON
BURNS LAKE
FORT ST JAMES
ENDAKO MINES
VANDERHOOF
FORT ST JOHN
TAYLOR
HUDSON HOPE
POWDER KING SKI
MACKENZIE
CHETWYND
LOUISIANA PACIFIC PULP MILL
DAWSON CREEK
TUMBLER RIDGE
BEAR LAKE
THE PAS LUMBER
SUMMIT LAKE
PRINCE GEORGE
BUCKHORN
HIXON
DUNKLEY LUMBER
QUESNEL
KERSLEY
ALBERTA
JASPER
GIBRALTAR MINES
WILLIAMS LAKE
150 MILE HOUSE
LAC LA HACHE
108 MILE HOUSE
HORSE LAKE
BRITISH COLUMBIA
McMURPHY
CLINTON
CACHE CREEK
ASHCROFT
CAMPBELL RIVER
COMOX
POWELL RIVER
WHISTLER
SQUAMISH
PORT ALBERNI
SAVONA
HIGHLAND VALLEY COPPER
KAMLOOPS
LOGAN LAKE
SORRENTO
CHASE
SALMON ARM
ENDERBY
REVELSTOKE
GOLDEN
FALKLAND
MERRITT
VERNON
LUMBY
COLDSTREAM
NANAIMO
VANCOUVER
KINGSVALE
WESTBANK
PEACHLAND
WINFIELD
KELOWNA
NARAMATA
PACIFIC OCEAN
CROFTON
HOPE
HUNTINGDON
PRINCETON
SUMMERLAND
PENTICTON
OKANAGAN FALLS
HEDLEY
KEREMEOS
OLIVER
OSOYOOS
FERNDALE
VICTORIA
LAUREL
ANACORTES
INVERMERE
FORDING COAL
CFI PULP AND PAPER SKOOKUMCHUCK
GREENHILL COAL
ELKFORD
LINE CREEK
ELKVIEW COAL
MIDWAY
GREENWOOD
ROBSON
NELSON
KIMBERLEY
SPARWOOD
CASTLEGAR
SALMO
FERNIE
GRAND FORKS
CHRISTINA LAKE
ROSSLAND
TRAIL
FRUITVALE
CRANBROOK
ELKO
CRESTON
BYRON CREEK COAL
YAHK
KINGSGATE
U.S.A.
WASHINGTON
IDAHO
MONTANA
99000-P-000-101-R1
NORTH VANCOUVER
WEST VANCOUVER
BURRARD THERMAL PLANT
COQUITLAM
BURNABY
PITT MEADOWS
VANCOUVER
NEW WESTMINSTER
MAPLE RIDGE
AGASSIZ
RICHMOND
MISSION
ROSEDALE
LNG PLANT
DELTA
SUMAS
ARROW
CHILLIWACK
ATCHELITZ
SURREY
MATSQUI
ABBOTSFORD
LANGLEY
McDERMOT
WHITE ROCK
ALDERGROVE
HUNTINGTON
LOWER MAINLAND DETAIL
U.S.A.



FORTIS BC

FORTIS BC (VANCOUVER ISLAND) NATURAL GAS SYSTEM MAP

PIPELINE SYSTEM

OVERLAND - MAIN PIPELINES
31.571 km of 12" (323.9 mm) O.D. ON MAINLAND
132.048 km of 10" (273.1 mm) O.D. ON MAINLAND
50.145 km of 10" (273.1 mm) O.D. ON TEXADA ISLAND
216.824 km of 10" (273.1 mm) O.D. ON VANCOUVER ISLAND (MAINLINE)
430.588 km

MARINE PIPELINES
12.278 km of 10" (273.1 mm) O.D. SECRET COVE NORTH
12.270 km of 10" (273.1 mm) O.D. SECRET COVE SOUTH
10.900 km of 10" (273.1 mm) O.D. POWELL RIVER NORTH
10.957 km of 10" (273.1 mm) O.D. POWELL RIVER SOUTH
23.679 km of 10" (273.1 mm) O.D. LITTLE RIVER NORTH
23.670 km of 10" (273.1 mm) O.D. LITTLE RIVER SOUTH
93.754 km

EXTENSION PIPELINES
0.717 km of 4" (114.3 mm) O.D. PT. MELLON EXTENSION
0.495 km of 4" (114.3 mm) O.D. WOODFIBRE EXTENSION
1.060 km of 4" (114.3 mm) O.D. POWELL RIVER EXTENSION
1.853 km of 6" (168.3 mm) O.D. PT. ALBERNI MILL EXTENSION
4.125 km

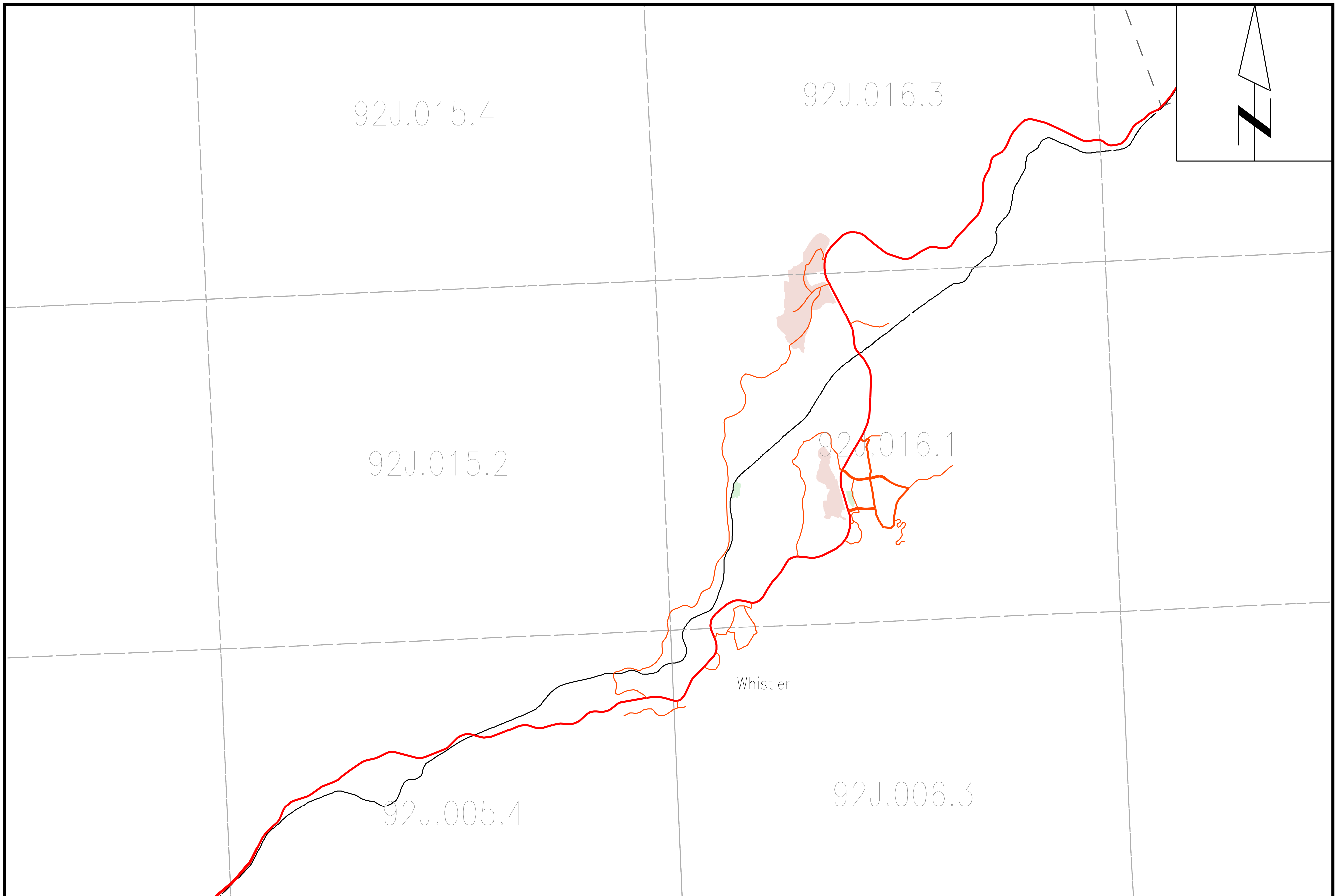
LATERALS
49.532 km of 8" (219.1 mm) O.D. CAMPBELL RIVER LATERAL
21.696 km of 6" (168.3 mm) O.D. PT. ALBERNI LATERAL
5.092 km of 6" (168.3 mm) O.D. CROFTON LATERAL
9.720 km of 6" (168.3mm) O.D. HARMAC LATERAL
86.040 km

TOTALS
430.588 km of OVERLAND PIPELINES (10" & 12")
93.754 km of MARINE PIPELINES (10")
90.165 km of LATERALS & EXTENSIONS (4",6" & 8")
614.507 km of TOTAL PIPELINES

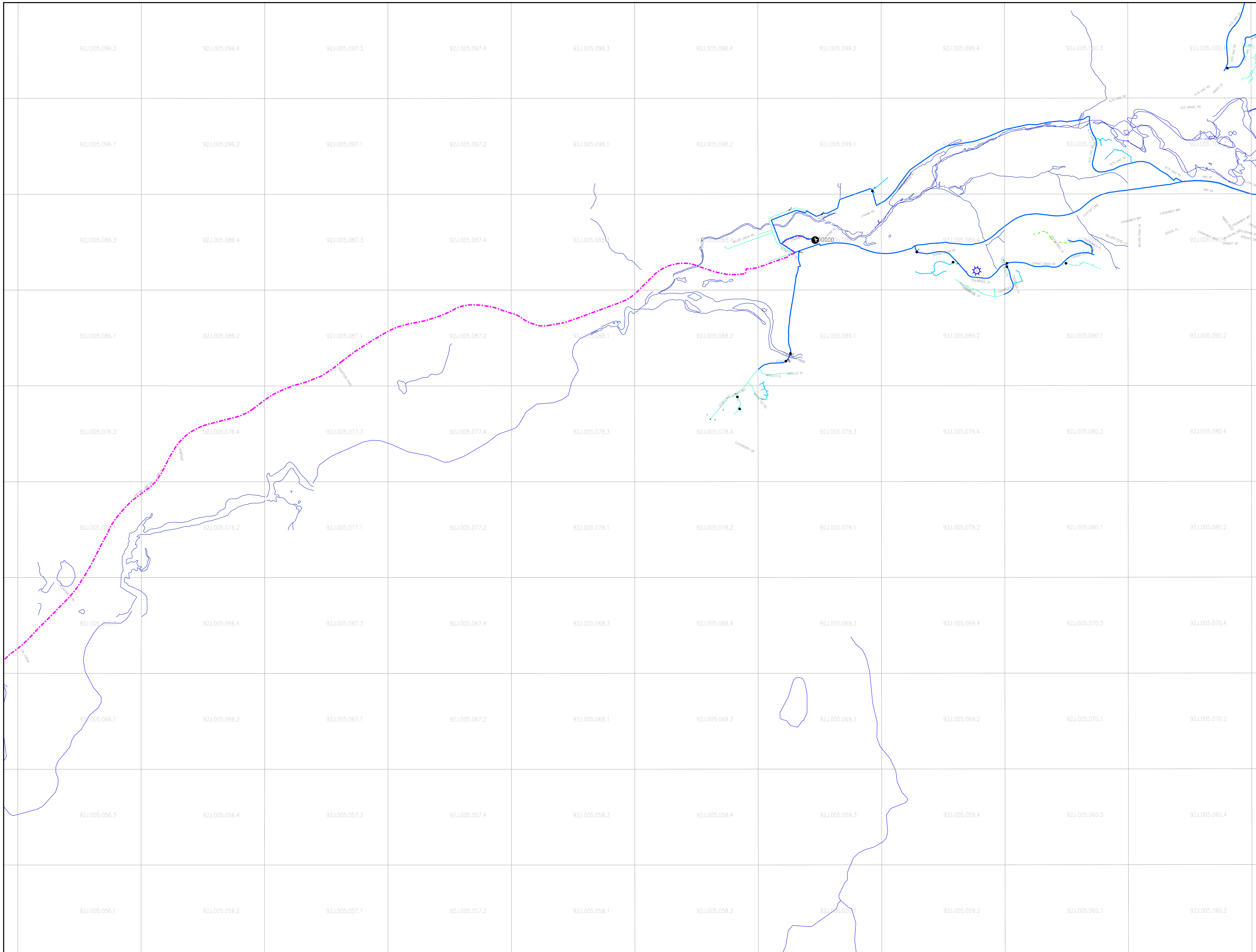
NOTE:
LENGTHS OF PIPELINES ARE APPROX. ONLY

ENGINEERING SERVICES	R2	WHISTLER IP PIPELINE ADDED	W KUMPULA			09-07-26
ENGINEERING SERVICES	R3	FORTIS BC LOGO ADDED	FSEDLAR			11-03-01
BY	No.	REVISION	DRAWN	DESIGNED	CHECKED	DATE(YY-MM-DD)
			MICROFILMED			SCALE- AS SHOWN

REF.- XXXXXXX	SAP ID: XXXXXXXXXX	DRAWING No. 96000-P-000-101-R2



WHISTLER	Page:	2011/01/19



Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

PROPOSED
INTERMEDIATE PRESSURE
DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
TRANSITION FITTING
VALVE
CRIMP STATION
GATE STATION
DISTRICT STATION
CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

92J.015.1	92J.015.2	92J.016.1
92J.005.3	92J.005.4	92J.006.3
92J.005.1	92J.005.2	92J.006.1

Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

DATE LAST REVISED

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PROPOSED
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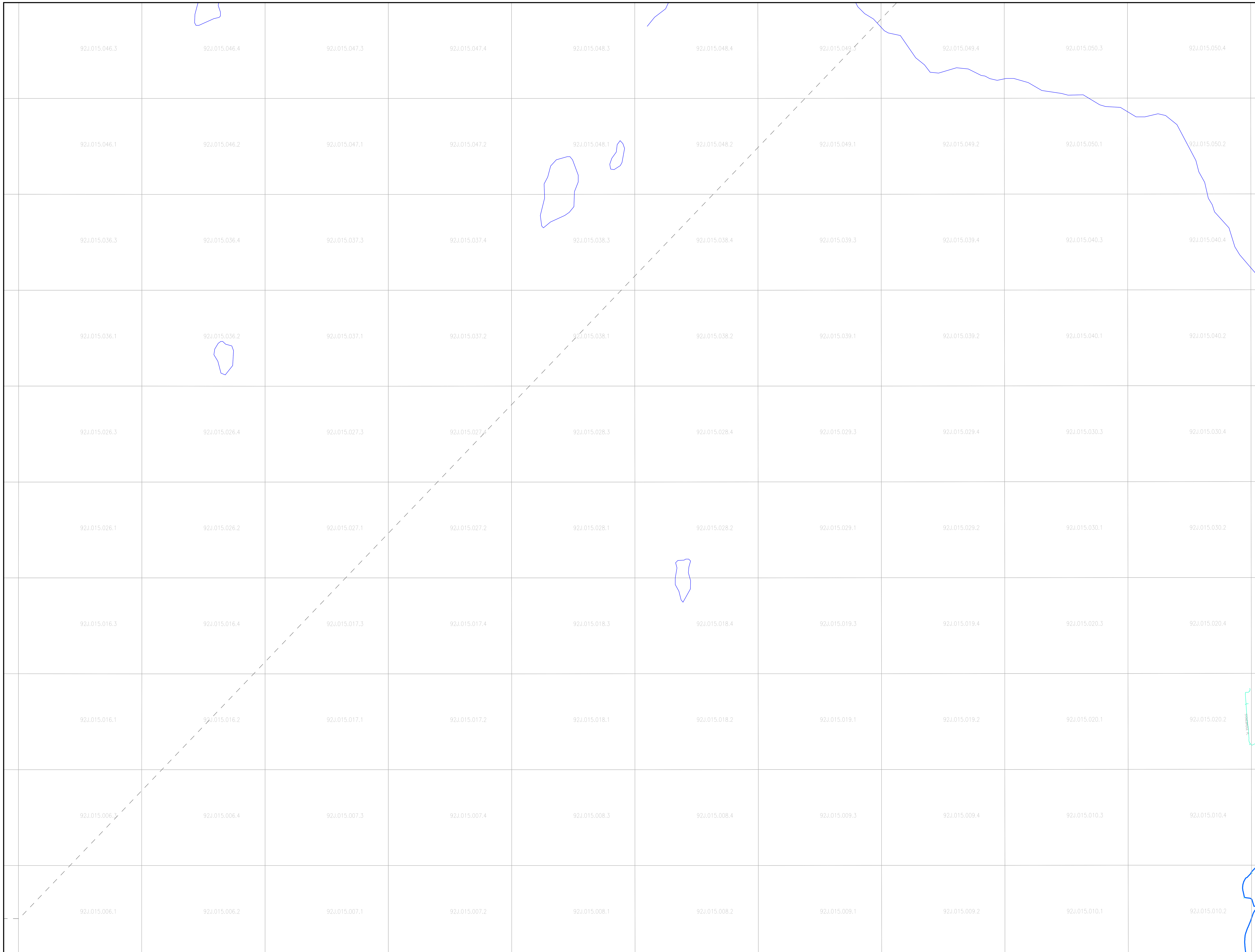
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

92J.015.2	92J.016.1	92J.016.2
92J.005.4	92J.006.3	92J.006.4
92J.005.2	92J.006.1	92J.006.2



Terasen Gas

DISTRIBUTION SERVICES

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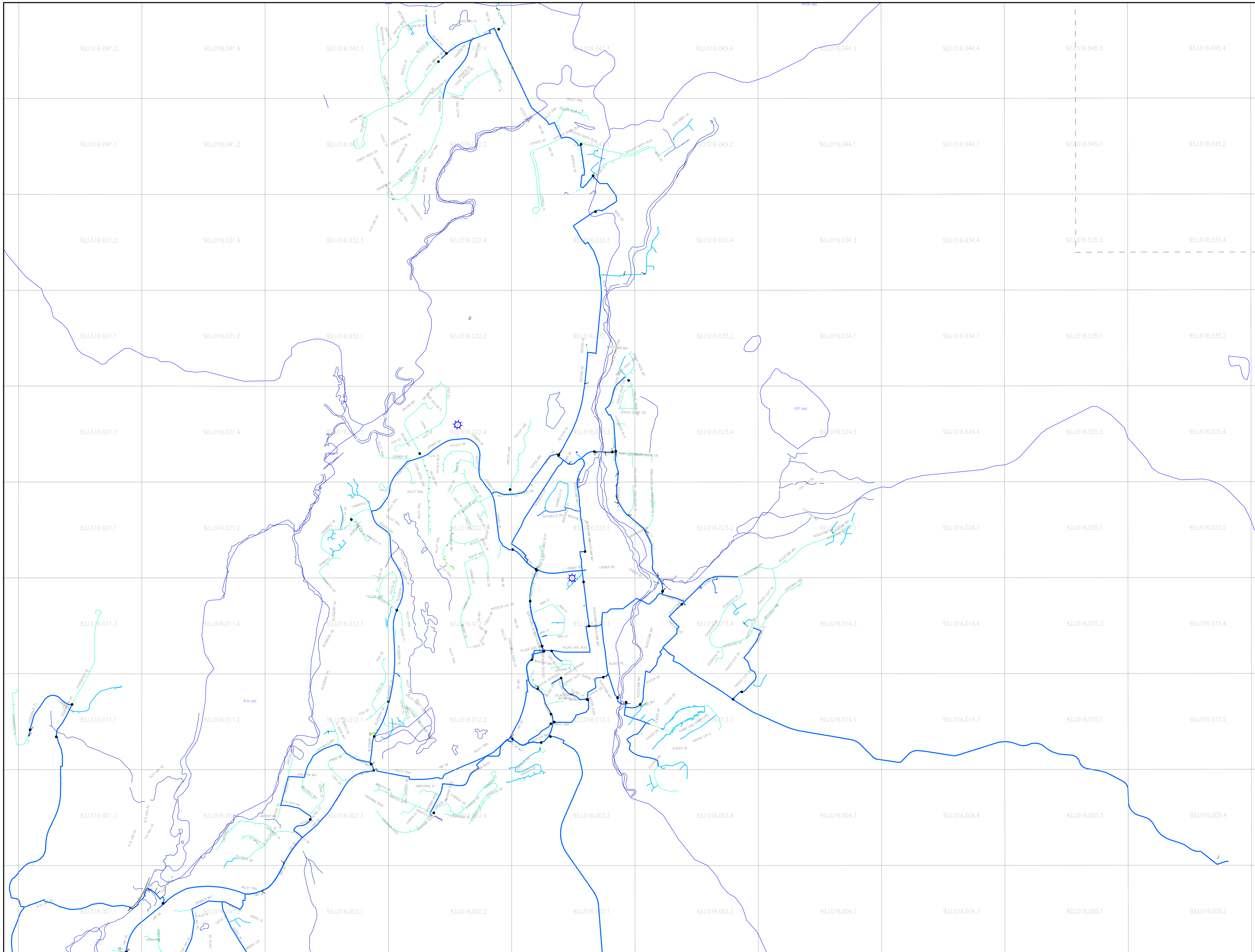
0m 100m 200m 300m 400m 500m 600m

92J.015.3	92J.015.4	92J.016.3
92J.015.1	92J.015.2	92J.016.1
92J.005.3	92J.005.4	92J.006.3



Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
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2011/01/19

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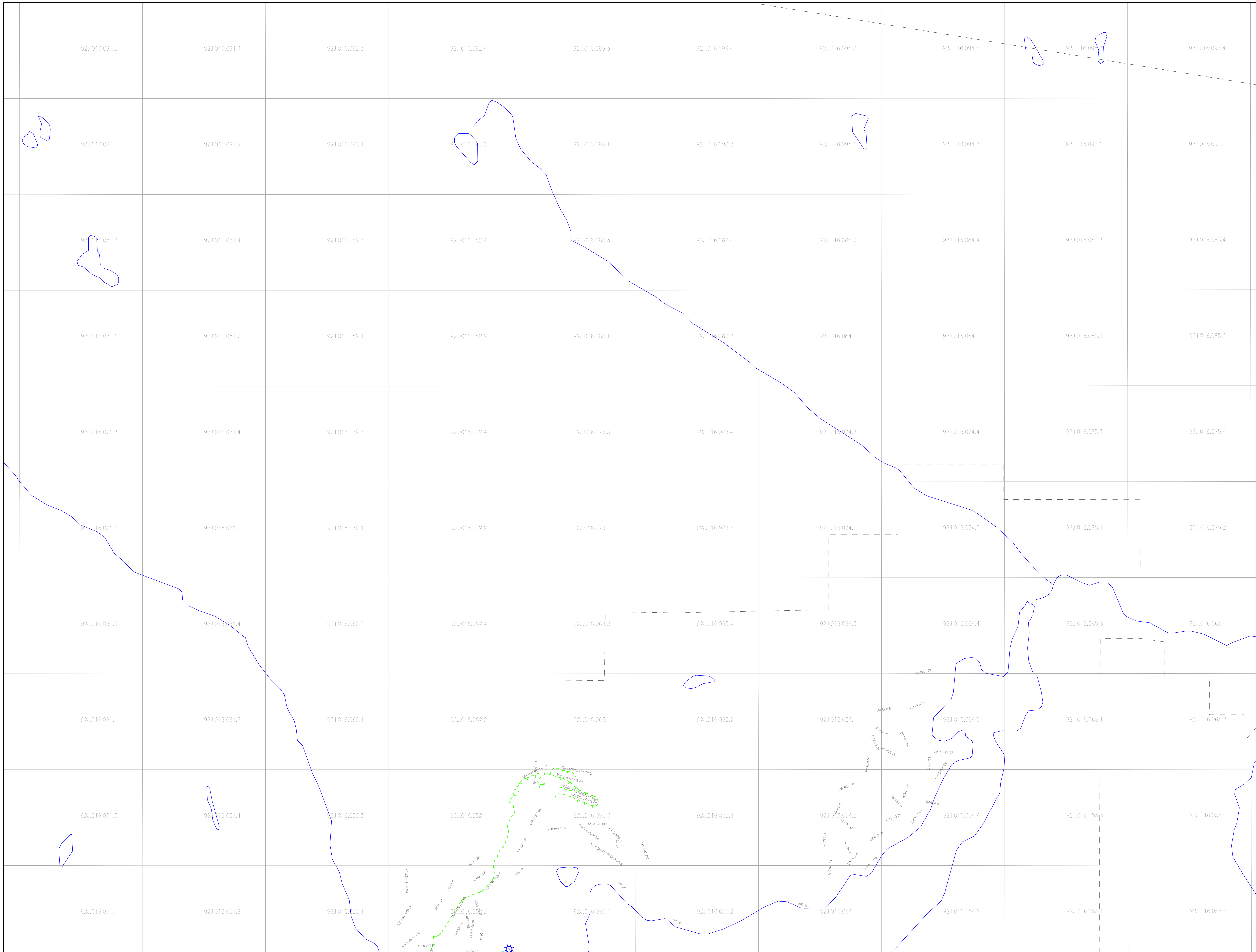
92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

92J.015.4	92J.016.3	92J.016.4
92J.015.2	92J.016.1	92J.016.2
92J.005.4	92J.006.3	92J.006.4



Terasen Gas

DISTRIBUTION SERVICES

16705 FRASER HWY., SURREY, B.C. V4N 0E8
1-888-224-2710

N

DATE LAST REVISED

2011/01/19

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DISTRIBUTION PRESSURE (700)
DISTRIBUTION PRESSURE – 60mm AND SMALLER
DISTRIBUTION PRESSURE – 88mm AND LARGER
TRANSMISSION PRESSURE

REDUCER
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CUSTOMER STATION
COMPRESSOR STATION
PROPANE PLANT
CNG STATION
FIRST CUT REG
TP SERVICE
CRITICAL CUSTOMER

92G.018.074.3 PLATE MAP NUMBER

0m 100m 200m 300m 400m 500m 600m

92J.025.2	92J.026.1	92J.026.2
92J.015.4	92J.016.3	92J.016.4
92J.015.2	92J.016.1	92J.016.2

1 GENERAL ASSUMPTIONS

This appendix includes the inflation, tax rate and debt assumptions and supporting information used in the determination of 2012 and 2013 revenue requirements. Historic information from 2006 to 2010 has also been provided.

Please refer to the Summary of General Assumptions page of this appendix for detail information for 2006-2013.

2 INFLATION

Introduction

The forecast British Columbia CPI is used as a cost driver for aspects of the cost of service because it is widely regarded as a reasonable measure of the forecast inflation applicable to the Province. The CPI is generally used to index wages, salaries, pension, and various other expenses.

Review History Highlights (2006-2010 Actuals)

Pursuant to the provisions of the Settlement Agreements (Order No. G-51-03 and Order No. G-33-07), the B.C. CPI inflation forecast was determined as the average of the forecasts from four reputable industry sources: Conference Board of Canada, B.C. Ministry of Finance, RBC Financial Group and the Toronto-Dominion Bank. In addition to the forecast CPI, and also in accordance with the Settlement Agreements, an adjustment factor was applied to the B.C. CPI to arrive at the inflation applied the formula operating and maintenance expense and formula capital additions throughout the 2006 – 2009 PBR period. The following table provides a summary of the B.C. CPI and the adjusted CPI embedded in the revenue requirements from 2006-2010:

Table C-1: Historic B.C. CPI and TGI Adjustment Factors (2006-2010)

	2006	2007	2008	2009	2010
CPI	2.20%	2.00%	2.00%	2.10%	1.80%
Adjustment Factor	-1.45%	-1.32%	-1.32%	-1.39%	
Adjusted CPI	0.75%	0.68%	0.68%	0.71%	1.80%

Table C-2: Summary of sources and dates of CPI forecasts are as follows:

Source	Forecast Publish Date
Conference Board of Canada	October 2010
B.C. Ministry of Finance	February 2011
RBC Financial Group	April 2011
Toronto-Dominion Bank	March 2011

3 ATTACHMENTS

The following attachments are included with this appendix:

1. Summary of General Assumptions, 2006 – 2013
2. Conference Board of Canada CPI report
3. B.C. Ministry of Finance CPI report
4. Royal Bank of Canada CPI report
5. Toronto Dominion Bank CPI report
6. Bank of Nova Scotia short-term interest rates
7. Toronto Dominion Bank short-term interest rates
8. Canadian Imperial Bank of Commerce short-term interest rates
9. Royal Bank of Canada short-term interest rates

Fortis BC Energy **"SUMMARY OF GENERAL ASSUMPTIONS"**

Line No.			2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2010 Approved	Variance	2011 Projected	2011 Approved	Variance	2012 Forecast	2013 Forecast
1	B.C. Inflation (CPI):	[1] Conference Board of Canada						2.27%			2.05%		2.16%	2.00%
2		[1] B.C. Ministry of Finance						2.20%			2.10%		2.00%	2.10%
3		[1] RBC Financial Group						1.50%			1.80%		1.80%	N/A
4		[1] Toronto Dominion Bank						1.60%			2.00%		2.00%	2.00%
5														
6		Average CPI	1.70%	2.00%	2.20%	2.00%	1.80%	1.90%	-0.10%	2.10%	2.00%	-0.10%	1.99%	2.03%
7														
8		Labour Inflation					3.00%	3.00%	0.00%	3.00%	3.00%	0.00%	1.50%	1.50%
9														
10	Income Tax Rate:	Federal					18.00%	18.00%		16.50%	16.50%		15.00%	15.00%
11		Provincial					10.50%	10.50%		10.00%	10.00%		10.00%	10.00%
12			34.12%	33.00%	31.50%	30.00%	28.50%	28.50%		26.50%	26.50%		25.00%	25.00%
13														
14	Foreign Exchange Rate:													
15		USD/CAD Exchange Rate	0.8800	0.9400	0.9400	0.8800	0.9700	0.8610	0.1090	1.0270	0.8871	- 0.1399	1.0125	1.0284
16		CAD/USD Exchange Rate	1.1364	1.0638	1.0638	1.1364	1.0309	1.1615	- 0.1306	0.9737	1.1273	0.1536	0.9876	0.9723
17														
18	Cost of Capital:													
19		**FEI**												
20		Short Term Debt Interest Rates	4.00%	4.75%	5.00%	4.25%	2.25%	2.25%	0.00%	2.00%	4.50%	2.50%	2.75%	3.75%
21		Long Term Debt Interest Rates	7.07%	7.02%	7.21%	6.96%	6.95%	5.24%	1.71%	4.75%	6.13%	1.38%	5.00%	5.50%
22		Return on Equity	10.65%	9.96%	10.83%	12.05%	9.42%	9.50%	-0.08%	9.50%	9.50%	0.00%	9.50%	9.50%
23		**FEVI**												
24		Short Term Debt Interest Rates	4.86%	5.18%	5.20%	2.86%	7.08%	2.50%	4.58%	3.25%	4.75%	-1.50%	4.25%	5.25%
25		Long Term Debt Interest Rates	4.91%	5.19%	5.98%	5.09%	4.62%	5.95%	-1.33%	5.00%	6.12%	-1.12%	5.25%	5.75%
26		Return on Equity	9.50%	9.07%	9.32%	9.59%	10.00%	10.00%	0.00%	10.00%	10.00%	0.00%	10.00%	10.00%
27		**FEW**												
28		Short Term Debt Interest Rates	5.68%	4.00%	4.00%	5.10%	2.89%	2.90%	-0.01%	2.75%	5.15%	-2.40%	3.75%	4.75%
29		Long Term Debt Interest Rates	4.90%	5.10%	5.10%	5.93%	5.11%	5.11%	0.00%	5.00%	5.11%	-0.11%	5.25%	5.75%
30		Return on Equity	8.96%	8.97%	9.22%	9.49%	8.68%	10.00%	-1.32%	10.00%	10.00%	0.00%	10.00%	10.00%
31														
32														
33	Forecast Prime Interest Rate and Short Term Debt Rate Spread:													
34		[2] Forecast Prime Interest Rate											4.57%	5.56%
35		FEI Short Term Debt Rate Spread											-1.82%	-1.81%
36		FEVI Short Term Debt Rate Spread											-0.32%	-0.31%
37		FEW Short Term Debt Rate Spread											-0.82%	-0.81%
38														
39														

[1] Please see Attachments C-3-2 through C-3-5 for inflation reports for 2012 and 2013

[2] Please see Attachments C-3-6 through C-3-9 for short-term interest rates for 2012 and 2013

The Conference Board of Canada

Forecast Completed: Oct. 28 2010

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2010Q1	2010Q2	2010Q3	2010Q4	2011Q1	2011Q2	2011Q3	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2010	2011	2012
G.D.P AT MARKET PRICES	195054	196725	199229	202016	204669	207329	210214	213263	216734	219902	223165	226267	198256	208869	221517
(MILLIONS $)	2.7	0.9	1.3	1.4	1.3	1.3	1.4	1.5	1.6	1.5	1.5	1.4	6.8	5.4	6.1
	12.2	12.2	12.2	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.4	12.4	12.2	12.3	12.4
G.D.P AT BASIC PRICES	179676	181330	183297	185867	188196	190526	193194	196011	199103	202052	205097	207987	182542	191982	203560
(MILLIONS $)	2.7	0.9	1.1	1.4	1.3	1.2	1.4	1.5	1.6	1.5	1.5	1.4	6.9	5.2	6.0
	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.1	12.1	12.1	12.1	12.1	12.0	12.0	12.1
G.D.P AT BASIC PRICES	152463	153177	153870	154535	154867	155898	157043	158252	159664	161043	162417	163837	153511	156515	161740
(MILLIONS $ 2002)	1.7	0.5	0.5	0.4	0.2	0.7	0.7	0.8	0.9	0.9	0.9	0.9	3.7	2.0	3.3
	12.5	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
CONSUMER PRICE INDEX (2002=1.0)	1.127	1.134	1.145	1.152	1.157	1.164	1.170	1.176	1.183	1.189	1.195	1.201	1.139	1.167	1.192
	0.5	0.7	1.0	0.5	0.5	0.6	0.5	0.5	0.6	0.5	0.5	0.5	1.5	2.4	2.2
IMPLICIT PRICE DEFLATOR -	1.178	1.184	1.191	1.203	1.215	1.222	1.230	1.239	1.247	1.255	1.263	1.269	1.189	1.227	1.258
GDP AT BASIC PRICES (2002=1.0)	1.0	0.4	0.6	1.0	1.0	0.6	0.7	0.7	0.7	0.6	0.6	0.5	3.1	3.2	2.6
AVERAGE WEEKLY WAGE	786	806	815	818	822	827	833	839	847	853	858	864	806	830	855
($, INDUSTRIAL COMPOSITE)	0.8	2.5	1.1	0.3	0.5	0.7	0.7	0.8	0.9	0.7	0.7	0.6	3.8	3.0	3.0
PERSONAL INCOME (MILLIONS $)	160905	163188	165793	167281	168820	170620	173051	175624	178093	180481	182728	184876	164292	172028	181545
	0.5	1.4	1.6	0.9	0.9	1.1	1.4	1.5	1.4	1.3	1.2	1.2	3.8	4.7	5.5
	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	13.0	13.0	13.0	12.9	12.9	13.0
PERSONAL DISPOSABLE INCOME	127737	132690	132143	133094	133942	135256	137112	139090	140915	142704	144435	146094	131416	136350	143537
(MILLIONS $)	0.3	3.9	-0.4	0.7	0.6	1.0	1.4	1.4	1.3	1.3	1.2	1.1	4.4	3.8	5.3
	13.0	13.0	13.1	13.1	13.0	13.0	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
PERSONAL SAVINGS RATE	-4.9	-2.0	-4.1	-4.4	-4.7	-4.9	-4.7	-4.7	-4.4	-4.5	-4.5	-4.5	-3.8	-4.7	-4.5
	11.5	59.8	-112.6	-5.3	-7.5	-3.8	3.2	0.0	6.5	-1.2	-0.7	-1.3	32.7	-23.9	5.7
POPULATION OF LABOUR	3751	3770	3791	3807	3822	3837	3852	3867	3881	3895	3910	3924	3780	3845	3902
FORCE AGE	0.5	0.5	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	2.0	1.7	1.5
	13.6	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.6	13.7	13.7
LABOUR FORCE ('000s)	2483	2485	2504	2509	2514	2518	2532	2547	2557	2571	2582	2591	2495	2528	2576
	0.6	0.1	0.8	0.2	0.2	0.1	0.5	0.6	0.4	0.5	0.4	0.3	2.0	1.3	1.9
	13.4	13.4	13.4	13.4	13.3	13.3	13.3	13.4	13.4	13.4	13.4	13.5	13.4	13.3	13.4
EMPLOYMENT ('000s)	2287	2298	2319	2327	2337	2347	2364	2384	2394	2411	2424	2436	2308	2358	2416
	0.8	0.5	0.9	0.4	0.4	0.4	0.7	0.8	0.4	0.7	0.5	0.5	2.1	2.2	2.5
	13.5	13.4	13.5	13.5	13.4	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5	13.4	13.5
UNEMPLOYMENT RATE	7.9	7.5	7.4	7.3	7.0	6.8	6.6	6.4	6.4	6.2	6.1	6.0	7.5	6.7	6.2
RETAIL SALES (MILLIONS $)	58150	57752	57691	58089	58498	59176	59936	60876	61462	62240	62998	63734	57920	59621	62608
	0.8	-0.7	-0.1	0.7	0.7	1.2	1.3	1.6	1.0	1.3	1.2	1.2	4.9	2.9	5.0
	13.4	13.4	13.2	13.2	13.2	13.2	13.2	13.3	13.3	13.3	13.3	13.3	13.3	13.2	13.3
HOUSING STARTS (NUMBER OF UNITS)	27200	26500	26133	25331	23873	24228	25742	26664	29274	29875	30221	30643	26291	25127	30003
	29.9	-2.6	-1.4	-3.1	-5.8	1.5	6.2	3.6	9.8	2.1	1.2	1.4	63.5	-4.4	19.4
	14.1	13.1	13.7	14.1	13.7	13.9	14.7	15.0	16.1	16.0	15.9	15.7	13.7	14.3	15.9

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

The Conference Board of Canada
Forecast Completed: Oct. 28 2010

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2013Q1	2013Q2	2013Q3	2013Q4	2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2013	2014	2015
G.D.P AT MARKET PRICES (MILLIONS $)	229344	232277	235047	237653	240006	242596	245272	247780	250303	252877	255312	257711	233580	243914	254051
	1.4	1.3	1.2	1.1	1.0	1.1	1.1	1.0	1.0	1.0	1.0	0.9	5.4	4.4	4.2
	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
G.D.P AT BASIC PRICES (MILLIONS $)	210850	213571	216134	218535	220691	223083	225557	227867	230196	232573	234815	237022	214773	224299	233652
	1.4	1.3	1.2	1.1	1.0	1.1	1.1	1.0	1.0	1.0	1.0	0.9	5.5	4.4	4.2
	12.2	12.2	12.2	12.2	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.2	12.1	12.1
G.D.P AT BASIC PRICES (MILLIONS $ 2002)	165579	166957	168211	169365	170288	171347	172380	173388	174435	175424	176378	177305	167528	171851	175886
	1.1	0.8	0.8	0.7	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.5	3.6	2.6	2.3
	12.4	12.5	12.5	12.5	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.5	12.4	12.4
CONSUMER PRICE INDEX (2002=1.0)	1.207	1.212	1.219	1.226	1.232	1.239	1.246	1.252	1.260	1.266	1.272	1.279	1.216	1.242	1.269
	0.5	0.4	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.5	2.0	2.2	2.2
IMPLICIT PRICE DEFLATOR - GDP AT BASIC PRICES (2002=1.0)	1.273	1.279	1.285	1.290	1.296	1.302	1.308	1.314	1.320	1.326	1.331	1.337	1.282	1.305	1.328
	0.3	0.5	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.5	0.4	0.4	1.9	1.8	1.8
AVERAGE WEEKLY WAGE ($, INDUSTRIAL COMPOSITE)	869	875	880	885	890	895	901	906	911	916	921	926	877	898	918
	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	2.5	2.4	2.3
PERSONAL INCOME (MILLIONS $)	187350	189612	191568	193445	195617	197579	199572	201510	203804	205783	207749	209750	190494	198570	206771
	1.3	1.2	1.0	1.0	1.1	1.0	1.0	1.0	1.1	1.0	1.0	1.0	4.9	4.2	4.1
	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
PERSONAL DISPOSABLE INCOME (MILLIONS $)	147908	149601	151101	152534	154104	155554	157086	158566	160272	161734	163233	164763	150286	156327	162500
	1.2	1.1	1.0	0.9	1.0	0.9	1.0	0.9	1.1	0.9	0.9	0.9	4.7	4.0	3.9
	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.1	13.1	13.2	13.2	13.1
PERSONAL SAVINGS RATE	-4.5	-4.6	-4.6	-4.6	-4.6	-4.6	-4.7	-4.7	-4.7	-4.7	-4.6	-4.5	-4.6	-4.7	-4.6
	0.8	-1.1	-0.7	-0.7	0.4	-0.9	-0.8	-1.1	1.7	-0.5	1.6	2.7	-2.2	-2.2	1.4
POPULATION OF LABOUR FORCE AGE	3937	3951	3966	3980	3994	4008	4022	4036	4050	4063	4077	4091	3959	4015	4070
	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	1.4	1.4	1.4
	13.7	13.7	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.7	13.8	13.8
LABOUR FORCE ('000s)	2603	2613	2621	2627	2631	2637	2645	2653	2660	2665	2669	2674	2616	2642	2667
	0.4	0.4	0.3	0.2	0.1	0.3	0.3	0.3	0.3	0.2	0.1	0.2	1.6	1.0	1.0
	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
EMPLOYMENT ('000s)	2448	2458	2466	2473	2479	2487	2494	2501	2509	2516	2523	2530	2461	2490	2520
	0.5	0.4	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.9	1.2	1.2
	13.5	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
UNEMPLOYMENT RATE	5.9	5.9	5.9	5.9	5.8	5.7	5.7	5.7	5.7	5.6	5.4	5.4	5.9	5.7	5.5
RETAIL SALES (MILLIONS $)	64522	65297	65970	66601	67281	67907	68520	69156	69818	70433	71026	71602	65598	68216	70720
	1.2	1.2	1.0	1.0	1.0	0.9	0.9	0.9	1.0	0.9	0.8	0.8	4.8	4.0	3.7
	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
HOUSING STARTS (NUMBER OF UNITS)	30852	31349	31842	32235	32776	32964	33289	33403	33686	33775	33783	33775	31569	33108	33755
	0.7	1.6	1.6	1.2	1.7	0.6	1.0	0.3	0.8	0.3	0.0	-0.0	5.2	4.9	2.0
	15.6	15.5	15.6	15.6	15.7	15.7	15.8	15.6	15.6	15.6	15.5	15.5	15.6	15.7	15.6

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

Table 3.7.2 Components of Nominal Income and Expenditure

					Forecast		
	2009	2010	2011	2012	2013	2014	2015
Labour income[1] ($ million)	100,698	104,171 [e]	108,366	113,463	118,726	124,291	130,054
(% change)	-1.7	3.4	4.0	4.7	4.6	4.7	4.6
Personal income ($ million)	156,986	161,630 [e]	167,326	174,879	182,562	190,632	199,005
(% change)	-0.1	3.0	3.5	4.5	4.4	4.4	4.4
Corporate profits before taxes ($ million)	18,258	21,807 [e]	23,672	25,218	26,935	29,012	31,303
(% change)	-21.3	19.4	8.6	6.5	6.8	7.7	7.9
Retail sales ($ million)	55,222	57,579 [e]	59,915	62,620	65,387	68,282	71,331
(% change)	-4.4	4.3	4.1	4.5	4.4	4.4	4.5
Housing starts	16,077	26,479	24,946	26,538	27,144	28,115	28,500
(% change)	-53.2	64.7	-5.8	6.4	2.3	3.6	1.4
Residential investment[2] ($ million)	15,755	19,177 [e]	19,890	21,233	22,327	23,661	24,923
(% change)	-15.5	21.7	3.7	6.7	5.2	6.0	5.3
BC consumer price index (2001 = 100)	112.3	113.8	116.1	118.5	120.9	123.4	126.0
(% change)	0.0	1.3	2.0	2.0	2.1	2.1	2.1

[1] Domestic basis; wages, salaries and supplementary labour income.

[2] Includes renovations and improvements.

[e] Ministry of Finance estimate.

Table 3.7.3 Labour Market Indicators

					Forecast		
	2009	2010	2011	2012	2013	2014	2015
Population (on July 1) (000's)	4,460	4,531	4,598	4,664	4,729	4,796	4,863
(% change)	1.7	1.6	1.5	1.4	1.4	1.4	1.4
Labour force population, 15+ Years (000's)	3,663	3,729	3,790	3,849	3,905	3,962	4,017
(% change)	2.1	1.8	1.6	1.5	1.5	1.4	1.4
Net in-migration (000's)							
– International[1,3]	50.8	48.5 [e]	46.3	44.3	43.4	44.0	43.4
– Interprovincial[3]	10.4	5.5 [e]	8.0	8.5	10.5	11.5	11.5
– Total	61.1	54.0 [e]	54.3	52.8	53.9	55.5	54.9
Participation rate[2] (%)	65.6	65.5	65.3	65.3	65.3	65.5	65.6
Labour force (000's)	2,403	2,443	2,475	2,511	2,550	2,593	2,636
(% change)	1.1	1.7	1.3	1.5	1.6	1.7	1.7
Employment (000's)	2,218	2,257	2,288	2,328	2,368	2,408	2,450
(% change)	-2.1	1.7	1.4	1.8	1.7	1.7	1.7
Unemployment rate (%)	7.7	7.6	7.5	7.2	7.1	7.1	7.0

[1] International migration includes net non-permanent residents and returning emigrants less net temporary residents abroad.

[2] Percentage of the population 15 years of age and over in the labour force.

[3] Components may not sum to total due to rounding.

[e] BC Stats estimate.

Economic forecast detail — United States

Real growth in the economy

Quarter-over-quarter annualized % change unless otherwise indicated

					Forecast										Forecast	
	2010				2011				2012				year-over-year % change			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2009	2010	2011	2012
Consumer spending	1.9	2.2	2.4	4.1	2.8	3.7	3.7	3.6	3.6	3.2	2.8	3.2	-1.2	1.8	3.3	3.4
Durables	8.8	6.8	7.6	21.0	7.7	10.1	10.3	9.1	8.5	6.7	6.7	6.7	-3.7	7.6	10.9	8.2
Non-durables	4.2	1.9	2.5	4.8	3.4	2.6	2.8	2.9	2.8	2.8	2.1	2.8	-1.2	2.8	3.2	2.7
Services	0.1	1.6	1.6	1.4	1.8	3.0	3.0	3.0	3.1	2.8	2.5	2.8	-0.8	0.5	2.1	2.9
Government spending	-1.6	3.9	3.9	-1.5	-0.8	0.0	-0.4	-0.8	-1.1	-0.9	-0.4	-0.1	1.6	1.0	0.1	-0.7
Residential investment	-12.3	25.6	-27.3	2.7	8.8	13.6	19.5	15.3	13.6	14.2	16.9	13.2	-22.9	-3.0	5.8	15.1
Business investment	7.8	17.2	10.0	5.3	5.9	16.2	17.0	16.5	15.0	13.9	12.0	10.0	-17.1	5.6	10.9	14.6
Non-residential structures	-17.8	-0.5	-3.6	4.5	-7.0	6.4	9.5	9.5	10.5	11.1	10.5	11.5	-20.4	-13.9	1.4	10.1
Equipment & software	20.5	24.8	15.4	5.5	10.6	19.8	19.8	19.0	16.7	14.9	12.6	9.5	-15.3	15.1	14.4	16.3
Final domestic demand	1.3	4.3	2.6	3.1	2.5	4.3	4.5	4.2	4.0	3.6	3.4	3.4	-3.1	1.8	3.4	3.9
Exports	11.4	9.1	6.7	9.6	10.1	9.1	8.5	9.9	9.3	9.7	9.7	8.7	-9.5	11.8	9.1	9.4
Imports	11.2	33.5	16.8	-12.4	13.5	11.0	9.8	10.3	10.1	10.5	9.9	7.5	-13.8	12.7	8.5	10.0
Inventories (change in $b)	44.1	68.8	121.4	7.1	67.0	77.1	76.9	77.4	78.4	76.9	71.2	72.7	-113.1	60.4	74.6	74.8
Real gross domestic product	**3.7**	**1.7**	**2.6**	**2.8**	**3.4**	**4.1**	**4.1**	**3.9**	**3.7**	**3.2**	**3.0**	**3.5**	**-2.6**	**2.8**	**3.4**	**3.6**

Other indicators

Year-over-year % change unless otherwise indicated

Business and labour																
Productivity	6.6	4.0	2.9	1.8	1.5	2.7	2.6	2.5	2.2	1.8	1.6	1.7	3.7	3.8	2.3	1.8
Pre-tax corporate profits	37.6	37.0	26.4	16.5	8.1	7.4	7.7	8.7	7.8	6.4	5.3	5.1	-0.4	28.6	8.0	6.1
Unemployment rate (%)*	9.7	9.6	9.6	9.6	9.0	8.9	8.8	8.6	8.5	8.4	8.2	8.0	9.3	9.6	8.8	8.3
Inflation																
Headline CPI	2.4	1.8	1.2	1.3	1.9	2.4	2.4	2.1	1.9	1.8	1.8	1.7	-0.4	1.6	2.2	1.8
Core CPI	1.3	0.9	0.9	0.7	1.0	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.7	1.0	1.1	1.4
External trade																
Current account balance ($b)	-437	-493	-509	-446	-468	-492	-511	-528	-547	-564	-580	-585	-378	-471	-500	-569
% of GDP	-3.0	-3.4	-3.5	-3.0	-3.1	-3.2	-3.3	-3.4	-3.4	-3.5	-3.6	-3.6	-2.7	-3.2	-3.2	-3.5
Housing starts (000s)*	617	602	588	534	576	610	683	726	799	863	927	991	554	585	649	895
Motor vehicle sales (millions, saar)*	11.0	11.3	11.6	12.3	12.9	13.3	13.6	13.9	14.1	14.2	14.4	14.5	10.4	11.5	13.4	14.3

*Period average

Source: Bureau of Economic Analysis, RBC Economics Research forecasts

CANADIAN ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2010				2011				2012				Annual Average			4th Qtr/4th Qtr		
	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	10	11F	12F	10	11F	12F
Real GDP	5.5	2.2	1.8	3.3	3.8	3.2	2.8	2.6	2.5	2.4	2.3	2.2	3.1	3.0	2.5	3.2	3.1	2.3
Consumer Expenditure	4.1	1.9	2.7	4.9	3.2	3.1	2.7	2.5	2.4	2.3	2.2	2.1	3.4	3.2	2.4	3.4	2.8	2.2
Durable Goods	4.4	-5.5	2.3	12.0	3.9	3.7	3.1	2.5	3.9	3.0	2.8	2.5	5.4	4.3	3.1	3.1	3.3	3.0
Business Investment	12.7	15.2	18.6	10.4	11.5	13.2	9.2	8.0	7.7	7.2	6.8	6.7	5.2	12.1	8.0	14.2	10.4	7.1
Non-Res. Structures	10.6	2.4	12.7	21.0	10.2	12.5	7.9	5.9	6.0	5.5	5.3	5.2	-0.5	11.8	6.4	11.5	9.1	5.5
Machinery & Equipment	14.8	29.7	24.6	0.7	13.0	14.0	10.5	10.2	9.5	9.0	8.4	8.2	11.2	12.5	9.7	16.9	11.9	8.8
Residential Investment	20.6	0.0	-3.9	-0.6	-8.2	-2.0	-1.5	-0.5	3.0	3.5	3.7	4.5	10.4	-3.3	1.7	3.6	-3.1	3.7
Government Expenditures	1.8	4.5	2.2	3.5	0.1	-2.2	-0.6	-0.3	-0.3	-0.4	-0.5	-0.6	5.0	0.7	-0.5	2.1	-0.3	-0.5
Final Domestic Demand	5.4	3.7	3.7	4.7	2.4	2.5	2.3	2.2	2.4	2.3	2.2	2.1	4.4	3.1	2.3	4.4	2.4	2.2
Exports	6.7	7.3	-1.7	17.1	9.0	8.4	6.9	6.3	6.4	5.9	5.6	5.0	6.4	8.4	6.3	7.2	7.6	5.7
Imports	13.6	19.7	7.8	0.5	15.6	6.9	6.5	5.7	5.8	5.5	5.7	3.5	13.4	8.5	5.7	10.1	8.6	5.1
Change in Non-Farm Inventories ($2002 Bn)	5.5	14.6	17.3	-6.6	3.5	4.5	5.8	6.5	6.5	6.3	6.8	6.2	7.7	5.1	6.5	—	—	—
Final Sales	2.8	-1.0	0.6	11.0	-0.3	2.9	2.4	2.4	2.5	2.3	2.0	2.7	1.8	2.9	2.4	3.2	1.8	2.4
International Current Account Balance ($Bn)	-34.3	-53.5	-67.9	-26.3	-32.2	-27.8	-27.7	-27.5	-23.9	-23.1	-23.5	-21.0	-45.5	-28.8	-22.9	—	—	—
% of GDP	-2.1	-3.3	-4.2	-1.6	-1.9	-1.6	-1.6	-1.6	-1.4	-1.3	-1.3	-1.2	-2.8	-1.7	-1.3	—	—	—
Pre-tax Corp. Profits	38.2	-6.9	0.4	41.1	12.6	10.0	8.6	8.1	8.0	7.9	7.8	7.6	18.4	13.1	8.1	16.2	9.8	7.8
% of GDP	10.8	10.5	10.4	11.2	11.3	11.4	11.5	11.6	11.7	11.8	11.9	12.0	10.7	11.5	11.9	—	—	--
GDP Deflator (Y/Y)	3.4	3.3	2.8	2.6	2.4	3.0	3.1	2.6	2.1	1.9	1.8	1.8	3.0	2.8	1.9	2.6	2.6	1.8
Nominal GDP	10.0	2.9	3.5	7.2	7.6	6.2	4.9	4.4	4.3	4.3	4.2	4.1	6.2	5.9	4.5	5.8	5.8	4.2
Labour Force	0.9	4.5	3.7	-1.0	3.2	1.7	1.2	1.3	1.1	1.0	0.8	0.8	1.1	1.5	1.1	0.9	1.8	0.9
Employment	1.5	5.6	4.8	0.6	2.8	2.0	1.8	1.5	1.3	1.2	1.1	1.0	1.4	1.9	1.4	1.7	2.0	1.1
Employment ('000s)	62	140	58	19	119	86	77	65	57	52	48	44	231	316	240	279	347	201
Unemployment Rate (%)	8.4	8.2	8.0	8.0	7.8	7.7	7.6	7.5	7.5	7.4	7.4	7.3	8.0	7.7	7.4	—	—	—
Personal Disp. Income	4.5	15.1	-5.1	7.3	5.3	4.5	3.9	4.3	3.9	4.0	4.0	3.9	4.6	4.5	4.0	5.2	4.5	4.0
Pers. Savings Rate (%)	3.4	6.3	3.9	4.0	4.1	3.8	3.7	3.7	3.7	3.8	3.8	3.9	4.4	3.8	3.8	—	—	—
Cons. Price Index (Y/Y)	1.6	1.4	1.8	2.3	2.3	2.6	2.3	2.2	2.0	1.9	2.0	2.0	1.8	2.4	2.0	2.3	2.2	2.0
Core CPI (Y/Y)	1.9	1.8	1.6	1.6	1.4	1.6	1.7	1.7	1.8	1.9	2.0	2.0	1.7	1.6	1.9	1.6	1.7	2.0
Housing Starts ('000s)	198	198	192	179	170	160	150	160	165	168	170	175	192	160	170	—	—	—
Productivity: Real GDP / worker (Y/Y)	1.7	1.8	1.7	1.5	0.8	1.4	1.5	1.0	1.1	1.1	1.1	1.2	1.7	1.2	1.1	1.5	1.0	1.2

F: Forecast by TD Economics as at March 2011

Source: Statistics Canada, Bank of Canada, Canada Mortgage and Housing Corporation, Haver Analytics

Scotia Economics' Long-term Forecast -- March 2011

	HISTORICAL											FORECAST			
												SHORT TERM		MEDIUM TERM	
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
CANADA															
Real GDP (y/y % ch)	3.9	3.1	2.9	1.9	3.1	3.0	2.8	2.2	0.5	-2.5	3.1	3.1	2.6	2.6	2.5
CPI Inflation (y/y % ch)	2.7	2.5	2.3	2.8	1.9	2.2	2.0	2.1	2.4	0.3	1.8	2.4	2.2	2.2	2.1
Nominal GDP (y/y % ch)	9.6	2.9	4.0	5.2	6.4	6.4	5.6	5.5	4.6	-4.5	6.2	5.7	4.8	4.8	4.6
Unemployment Rate (%)	6.8	7.3	7.7	7.6	7.2	6.7	6.3	6.0	6.1	8.3	8.0	7.6	7.4	7.2	7.0
Housing Starts (000s)	152	163	205	218	233	225	227	228	211	149	190	175	175	180	180
Auto Sales (000s)	1550	1571	1704	1594	1533	1586	1616	1654	1642	1461	1557	1590	1605	1615	1570
Overnight Rate (%)	5.49	4.24	2.45	2.94	2.25	2.65	4.01	4.35	3.04	0.43	0.59	1.15	2.20	2.75	3.25
10-year Bond (%)	5.93	5.48	5.29	4.81	4.58	4.07	4.21	4.27	3.61	3.23	3.24	3.35	3.85	4.60	4.90
UNITED STATES															
Real GDP (y/y % ch)	4.1	1.1	1.8	2.5	3.6	3.1	2.7	1.9	0.0	-2.6	2.8	3.0	2.7	2.5	2.5
CPI Inflation (y/y % ch)	3.4	2.8	1.6	2.3	2.7	3.4	3.2	2.9	3.8	-0.3	1.6	1.9	1.8	2.2	2.3
Nominal GDP (y/y % ch)	6.4	3.4	3.5	4.7	6.5	6.5	6.0	4.9	2.2	-1.7	3.8	4.4	4.3	4.7	4.8
Unemployment Rate (%)	4.0	4.8	5.8	6.0	5.5	5.1	4.6	4.6	5.8	9.3	9.6	9.0	8.5	8.3	8.1
Housing Starts (millions)	1.57	1.60	1.71	1.85	1.95	2.07	1.81	1.34	0.90	0.55	0.59	0.65	0.85	1.10	1.20
Auto Sales (millions)	17.3	17.1	16.8	16.6	16.9	16.9	16.5	16.1	13.2	10.4	11.6	12.7	13.5	14.2	14.5
Fed Funds Rate (%)	6.24	3.88	1.67	1.13	1.35	3.22	4.97	5.02	1.92	0.16	0.18	0.25	1.45	2.50	3.00
10-year Bond (%)	6.03	5.02	4.61	4.01	4.27	4.29	4.80	4.63	3.66	3.26	3.22	3.55	4.25	5.00	5.25
CURRENCIES & COMMODITIES															
Canadian Dollar (USD/CAD)	1.49	1.55	1.57	1.40	1.30	1.21	1.13	1.07	1.06	1.14	1.03	0.96	0.93	0.91	0.93
Canadian Dollar (CAD/USD)	0.67	0.65	0.64	0.71	0.77	0.83	0.88	0.94	0.94	0.88	0.97	1.04	1.07	1.10	1.08
Euro (EUR/USD)	0.92	0.89	0.94	1.13	1.24	1.24	1.26	1.37	1.47	1.39	1.33	1.37	1.42	1.47	1.44
WTI Crude Oil (US$/bbl)	30.4	26.1	26.1	31.1	41.5	56.6	66.1	72.3	99.8	61.7	79.4	97	100	110	110

** All data are annual averages.*

INTEREST RATE OUTLOOK	Annual Average						End of Period					
	2010	2011F	2012F	2013F	2014F	2015F	2010	2011F	2012F	2013F	2014F	2015F
CANADIAN FIXED INCOME												
Overnight Target Rate (%)	0.69	1.38	2.63	3.56	3.75	3.75	1.00	2.00	3.00	3.75	3.75	3.75
3-mth T-Bill Rate (%)	0.68	1.39	2.65	3.61	3.80	3.80	1.04	2.00	3.05	3.80	3.80	3.80
2-yr Govt. Bond Yield (%)	1.55	2.26	3.20	3.90	4.15	4.15	1.68	2.60	3.45	4.15	4.15	4.15
5-yr Govt. Bond Yield (%)	2.42	3.13	3.71	4.26	4.35	4.35	2.42	3.50	3.80	4.35	4.35	4.35
10-yr Govt. Bond Yield (%)	3.13	3.80	4.34	4.63	4.75	4.75	3.12	4.05	4.40	4.75	4.75	4.75
10-yr-2-yr Govt. Spread (%)	1.59	1.54	1.14	0.73	0.60	0.60	1.44	1.45	0.95	0.60	0.60	0.60
U.S. FIXED INCOME												
Fed Funds Target Rate (%)	0.25	0.25	0.63	2.56	3.75	3.75	0.25	0.25	1.00	3.50	3.75	3.75
3-mth T-Bill Rate (%)	0.15	0.16	0.69	2.66	3.85	3.85	0.12	0.20	1.10	3.60	3.85	3.85
2-yr Govt. Bond Yield (%)	0.66	0.76	1.49	3.04	4.00	4.05	0.59	0.90	1.95	3.75	4.05	4.05
5-yr Govt. Bond Yield (%)	1.90	2.44	3.08	4.10	4.63	4.80	2.01	2.75	3.35	4.50	4.70	4.80
10-yr Govt. Bond Yield (%)	3.14	3.75	4.14	4.56	5.06	5.35	3.29	3.95	4.20	4.75	5.25	5.35
10-yr-2-yr Govt. Spread (%)	2.48	2.99	2.65	1.53	1.06	1.30	2.70	3.05	2.25	1.00	1.20	1.30
CANADA-U.S. SPREADS												
3-mth T-Bill Rate (%)	0.53	1.23	1.96	0.95	-0.05	-0.05	0.92	1.80	1.95	0.20	-0.05	-0.05
2-yr Govt. Bond Yield (%)	0.89	1.50	1.71	0.86	0.15	0.10	1.09	1.70	1.50	0.40	0.10	0.10
5-yr Govt. Bond Yield (%)	0.52	0.69	0.64	0.16	-0.28	-0.45	0.41	0.75	0.45	-0.15	-0.35	-0.45
10-yr Govt. Bond Yield (%)	-0.01	0.05	0.20	0.06	-0.31	-0.60	-0.17	0.10	0.20	0.00	-0.50	-0.60

Source: Bloomberg, TDBFG, Forecast by TD Bank Financial Group

ECONOMIC UPDATE

CANADA	10Q4A	11Q1F	11Q2F	11Q3F	11Q4F	12Q1F	12Q2F	2010A	2011F	2012F
Real GDP Growth (AR)	3.3	4.0	2.5	2.0	1.9	2.3	3.1	3.1	2.8	2.8
Real Final Domestic Demand (AR)	4.7	2.5	2.5	1.9	1.8	2.3	3.0	4.4	3.0	2.7
All Items CPI Inflation (Y/Y)	2.3	2.4	2.8	2.6	2.2	1.7	1.5	1.8	2.5	1.8
Core CPI Ex Indirect Taxes (Y/Y)	1.6	1.2	1.4	1.8	1.9	1.9	1.8	1.7	1.6	2.0
Unemployment Rate (%)	7.7	7.7	7.5	7.6	7.8	7.7	7.5	8.0	7.6	7.4

U.S.	10Q4A	11Q1F	11Q2F	11Q3F	11Q4F	12Q1F	12Q2F	2010A	2011F	2012F
Real GDP Growth (AR)	3.1	2.8	3.0	2.3	1.9	2.4	2.5	2.9	2.7	2.4
Real Final Sales (AR)	6.7	1.6	3.3	2.7	2.3	2.2	2.5	1.4	2.9	2.5
All Items CPI Inflation (Y/Y)	1.3	2.0	2.4	2.8	2.5	1.9	1.6	1.6	2.4	1.8
Core CPI Inflation (Y/Y)	0.7	1.1	1.2	1.3	1.4	1.6	1.6	1.0	1.3	1.7
Unemployment Rate (%)	9.6	9.0	9.0	9.2	9.3	9.3	9.1	9.6	9.1	8.9

CANADA

With energy prices set to stay lofty for longer, we've revised up our 2011 CPI call by three ticks to 2.5%, although core should come in at a slightly tamer 1.6%, given its recent weakness. Growth is still on track to hit 2.8% for 2011, helped by a strong start, as rebounding manufacturing activity looks to take the Q1 growth rate to 4%. But with fiscal drag and rate hikes on their way in the second half of the year, economic growth should revert to a lower gear.

UNITED STATES

We've slashed our US first quarter growth rate to 2.8%, after having expected growth to top 4% a month ago, prior to the deepening supply shock to oil prices. The downward revision is centred on consumption, where weakness in wage gains, falling house prices and costly gasoline has put the squeeze on spending. Business capital spending also looks to be coming up short. We expect even slower growth in the second half, in part allowing for fiscal restraint that Republicans are pushing for. Our CPI targets are higher in the near term due to the shock to gasoline.

Financial market forecast detail

Interest rates

%, end of period

	10Q3	10Q4	Forecast 11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	Forecast 2011	2012
Canada														
Overnight rate	1.00	1.00	1.00	1.25	1.75	2.00	2.25	2.50	2.75	3.00	0.25	1.00	2.00	3.00
Three-month T-bills	0.88	0.97	1.10	1.35	2.00	2.05	2.55	3.05	3.50	3.60	0.19	0.97	2.05	3.60
Two-year GoC bonds	1.40	1.71	1.85	2.25	2.60	2.85	3.05	3.25	3.50	3.85	1.47	1.71	2.85	3.85
Five-year GoC bonds	2.04	2.46	2.65	2.75	3.00	3.30	3.50	3.65	3.85	4.05	2.77	2.46	3.30	4.05
10-year GoC bonds	2.75	3.16	3.25	3.30	3.40	3.80	3.95	4.05	4.15	4.15	3.61	3.16	3.80	4.15
30-year GoC bonds	3.34	3.55	3.85	3.90	4.15	4.40	4.45	4.50	4.50	4.55	4.07	3.55	4.40	4.55
Yield curve (10s-2s)	135	145	140	105	80	95	90	80	65	30	214	145	95	30
United States														
Fed funds rate	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.75	1.50	2.00	0 to 0.25	0 to 0.25	0 to 0.25	2.00
Three-month T-bills	0.16	0.12	0.15	0.20	0.25	0.30	0.35	0.90	1.65	2.10	0.06	0.12	0.30	2.10
Two-year bonds	0.44	0.61	0.70	1.00	1.15	1.55	2.00	2.30	2.60	3.05	1.14	0.61	1.55	3.05
Five-year bonds	1.27	2.01	2.10	2.20	2.30	2.70	3.00	3.25	3.50	3.75	2.69	2.01	2.70	3.75
10-year bonds	2.48	3.30	3.45	3.50	3.60	4.00	4.15	4.25	4.45	4.50	3.85	3.30	4.00	4.50
30-year bonds	3.67	4.34	4.50	4.55	4.60	4.85	4.90	4.95	5.00	5.05	4.63	4.34	4.85	5.05
Yield curve (10s-2s)	204	269	275	250	245	245	215	195	185	145	271	269	245	145
Yield spreads														
Three-month T-bills	0.72	0.85	0.95	1.15	1.75	1.75	2.20	2.15	1.85	1.50	0.13	0.85	1.75	1.50
Two-year	0.96	1.10	1.15	1.25	1.45	1.30	1.05	0.95	0.90	0.80	0.33	1.10	1.30	0.80
Five-year	0.77	0.45	0.55	0.55	0.70	0.60	0.50	0.40	0.35	0.30	0.08	0.45	0.60	0.30
10-year	0.27	-0.14	-0.20	-0.20	-0.20	-0.20	-0.20	-0.20	-0.30	-0.35	-0.24	-0.14	-0.20	-0.35
30-year	-0.33	-0.79	-0.65	-0.65	-0.45	-0.45	-0.45	-0.45	-0.50	-0.50	-0.56	-0.79	-0.45	-0.50

Exchange rates

%, end of period

	10Q3	10Q4	Forecast 11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009	2010	Forecast 2011	2012
Australian dollar	0.97	1.02	1.00	0.99	0.98	0.97	0.96	0.95	0.94	0.94	0.90	1.02	0.97	0.94
Brazilian real	1.70	1.66	1.73	1.75	1.77	1.78	1.76	1.75	1.73	1.72	1.74	1.66	1.78	1.72
Canadian dollar	1.03	1.00	0.97	0.95	0.95	0.95	0.97	1.00	1.02	1.02	1.05	1.00	0.95	1.02
Renmibi	6.69	6.59	6.50	6.40	6.30	6.20	6.10	6.00	5.90	5.80	6.83	6.59	6.20	5.80
Euro	1.36	1.34	1.39	1.36	1.32	1.30	1.30	1.30	1.29	1.29	1.43	1.34	1.30	1.29
Yen	84	81	81	81	84	87	90	95	100	105	93.00	81.00	87.00	105.00
Mexican peso	12.59	12.36	11.75	11.75	12.00	12.00	12.00	12.50	12.25	12.00	13.10	12.36	12.00	12.00
New Zealand dollar	0.73	0.78	0.74	0.72	0.70	0.69	0.68	0.68	0.68	0.69	0.73	0.78	0.69	0.69
Swiss franc	0.98	0.93	0.92	0.93	0.95	0.96	0.97	0.97	0.98	0.98	1.04	0.93	0.96	0.98
U.K. pound sterling	1.57	1.56	1.65	1.66	1.65	1.65	1.67	1.69	1.70	1.72	1.62	1.56	1.65	1.72

Source: Reuters, RBC Economics Research forecasts

Appendix C-2

FORECASTING TABLES

ACTUAL USE PER CUSTOMER RATES 2003 - 2010 (GJ/yr)

Lower Mainland Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Rate 1	104.9	99.2	102.0	101.8	109.0	110.3	106.8	93.0
Rate 2	306.2	294.8	308.9	319.1	347.6	359.7	352.5	302.7
Rate 3	3,142.1	3,249.7	3,312.9	3,221.6	3,553.1	3,651.1	3,426.7	3,208.9
Rate 23	4,675.6	4,607.6	4,564.5	4,569.0	4,881.2	4,870.8	4,961.2	4,546.1

Inland Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Rate 1	84.0	82.4	82.0	79.0	82.5	84.0	85.0	72.1
Rate 2	275.6	275.1	282.1	274.2	295.5	306.2	314.1	260.9
Rate 3	3,431.6	3,422.0	3,467.7	3,376.2	3,575.6	3,723.0	3,648.2	3,270.5
Rate 23	5,731.3	5,505.6	4,790.4	5,016.2	5,379.2	5,313.4	5,604.0	5,152.7

Columbia Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Rate 1	94.2	87.1	89.3	82.8	86.6	87.4	87.8	80.7
Rate 2	331.8	325.9	325.6	318.0	336.4	348.8	340.5	310.2
Rate 3	3,190.6	3,439.1	3,636.9	3,340.1	3,551.2	3,989.3	3,825.1	3,572.4
Rate 23	3,062.8	3,736.6	4,325.5	4,341.0	4,673.7	4,729.7	4,675.2	4,810.6

Revelstoke Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Rate 1	59.9	64.4	62.0	69.2	59.5	51.7	59.1	46.5
Rate 2	342.3	349.1	350.0	284.8	307.4	317.4	319.8	285.6
Rate 3	5,945.2	7,768.9	5,836.2	4,649.3	4,676.9	4,358.1	4,380.1	4,680.6

Mainland Consolidated - All Regions:

	2003	2004	2005	2006	2007	2008	2009	2010
Rate 1	98.8	94.2	96.1	95.0	101.1	102.3	100.2	86.8
Rate 2	299.0	291.0	302.0	307.0	333.0	345.0	341.7	291.6
Rate 3	3,193.0	3,287.0	3,348.0	3,251.0	3,560.0	3,669.0	3,468.9	3,228.0
Rate 23	4,816.0	4,754.0	4,596.0	4,638.0	4,959.0	4,944.0	5,064.7	4,648.5

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010
RGS	59.4	54.9	56.3	59.4	58.3	60.1	56.6	50.8
SCS1	65.2	61.4	69.0	74.0	93.0	108.7	115.1	98.5
SCS2	293.5	278.0	299.9	311.4	317.0	327.1	334.9	325.1
LCS1	892.8	854.2	913.2	894.9	959.0	995.7	1,002.1	982.2
LCS2	2,306.5	2,234.7	2,325.1	2,270.2	2,440.0	2,439.7	2,481.3	2,469.2
AGS	1,211.0	1,342.6	1,329.6	1,365.5	1,392.0	1,358.8	1,310.5	1,274.8
LCS3	16,343.3	16,053.1	16,344.2	17,162.0	17,979.0	17,150.7	16,368.2	16,077.9

Whistler:

	2003	2004	2005	2006	2007	2008	2009	2010
SGS-R				84.0	96.0	94.0	86.0	97.0
SGS-C				216.0	264.0	323.0	259.0	330.0
LGS-1				1,146.0	1,281.0	1,363.0	1,232.0	1,581.0
LGS-2				3,188.0	3,222.0	2,835.0	2,537.0	2,774.0
LGS-3				12,837.0	11,799.0	11,323.0	9,346.0	8,762.0

Fort Nelson

	2003	2004	2005	2006	2007	2008	2009	2010
RATE1	157.8	154.3	140.1	140.1	145.1	144.7	147.5	135.8
RATE2_1	548.8	532.9	457.1	476.8	482.8	464.6	493.1	449.7
RATE2_2	3,385.3	3,783.7	3,308.2	3,264.7	3,119.7	3,209.6	3,547.4	3,269.6

NORMALIZED ACTUAL USE PER CUSTOMER RATES 2003 - 2013 (GJ/yr)

Lower Mainland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	111.6	109.8	103.6	103.2	102.6	99.5	100.2	99.8	99.0	98.1	97.2
Rate 2	329.8	322.9	314.2	324.8	327.4	326.4	335.6	324.7	323.9	323.1	322.2
Rate 3	3,370.7	3,485.3	3,364.7	3,266.9	3,404.6	3,406.3	3,352.9	3,338.3	3,316.6	3,295.0	3,273.5
Rate 23	4,866.7	5,016.9	4,699.5	4,605.6	4,684.1	4,641.9	4,798.1	4,769.0	4,798.5	4,828.2	4,858.1

Inland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	88.7	85.7	81.9	81.6	80.3	76.0	76.9	75.7	74.7	73.8	72.9
Rate 2	296.0	286.4	280.7	285.6	286.0	272.8	281.5	275.8	272.7	269.5	266.4
Rate 3	3,702.4	3,524.3	3,451.3	3,536.2	3,500.4	3,426.0	3,423.7	3,494.9	3,493.6	3,492.2	3,490.9
Rate 23	5,816.0	5,712.5	4,791.9	5,139.6	5,273.1	4,997.9	5,350.3	5,254.5	5,255.2	5,256.0	5,256.7

Columbia Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	96.0	90.5	89.2	86.8	86.8	83.0	83.5	81.9	80.9	79.9	78.9
Rate 2	338.3	340.2	330.2	327.9	340.0	336.2	321.3	316.6	309.5	302.5	295.7
Rate 3	3,358.3	3,565.6	3,681.2	3,409.2	3,618.8	3,898.2	3,691.7	3,571.6	3,561.8	3,551.9	3,542.1
Rate 23	3,690.6	3,852.1	4,324.3	4,498.3	4,636.6	4,515.7	4,469.1	4,875.3	4,963.9	5,054.0	5,145.8

Revelstoke Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	69.3	70.6	63.6	68.9	57.9	49.2	55.9	51.6	50.1	48.6	47.1
Rate 2	349.0	369.8	353.5	312.9	296.8	300.7	309.8	309.0	316.1	323.4	330.8
Rate 3	6,529.2	8,049.0	5,914.3	4,954.3	4,580.5	4,210.5	4,267.6	4,892.9	5,022.3	5,155.1	5,291.4

Mainland Consolidated - All Regions:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	104.8	102.6	97.2	96.8	96.0	92.5	93.3	92.6	91.7	90.8	89.9
Rate 2	321.2	313.8	305.8	314.3	316.5	312.2	320.6	311.3	309.6	308.0	306.4
Rate 3	3,428	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,352	3,334	3,316
Rate 23	5,015	5,113	4,714	4,686	4,778	4,698	4,886	4,850	4,875	4,901	4,926

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
RGS	60.3	57.5	57.3	60.2	57.0	56.1	53.5	52.4	50.5	48.6	46.9
SCS1	66.2	63.7	70.0	75.1	90.7	102.6	110.1	101.1	105.7	110.1	114.7
SCS2	295.8	284.9	303.4	313.8	310.3	313.0	325.4	330.2	338.8	347.0	355.5
LCS1	898.5	882.5	926.4	903.2	943.1	952.0	979.7	997.1	1,023.4	1,048.7	1,074.6
LCS2	2,319.4	2,318.3	2,365.1	2,295.4	2,406.0	2,359.0	2,430.4	2,490.4	2,542.0	2,591.2	2,641.4
AGS	1,243.9	1,402.3	1,350.4	1,387.1	1,366.7	1,297.0	1,260.9	1,300.8	1,283.4	1,264.0	1,244.9
LCS3	16,476.5	16,650.4	16,630.0	17,378.9	17,694.3	16,521.0	15,793.3	16,342.2	16,342.0	16,342.0	16,342.0

Whistler:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
SGS-R				85.6	95.7	95.2	82.6	99.5	101.7	104.0	106.3
SGS-C				218.6	265.1	308.2	251.0	338.0	374.5	414.9	459.7
LGS-1				1,149.6	1,284.7	1,308.7	1,185.3	1,595.3	1,658.7	1,724.5	1,793.0
LGS-2				3,203.7	3,214.1	2,874.2	2,454.4	2,802.6	2,647.2	2,500.3	2,361.6
LGS-3				13,092.6	11,853.0	10,972.0	9,174.7	8,872.2	7,409.2	6,187.4	5,167.1

Fort Nelson

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate 1	162.3	155.1	153.7	141.5	141.9	139.6	138.4	140.9	140.6	140.3	140.0
Rate 2.1	563.6	537.3	502.1	486.5	472.0	448.9	464.0	468.1	467.2	466.2	465.2
Rate 2.2	3,404.2	3,814.7	3,634.5	3,302.8	3,083.7	3,137.1	3,370.7	3,387.5	3,496.7	3,609.4	3,725.7

CUSTOMER ADDITIONS 2003 - 2013

Lower Mainland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	4,892	7,802	7,833	6,159	8,053	4,636	3,183	4,574	4,366	4,617	4,813
Commercial[2]	-716	375	647	358	890	895	226	35	77	77	77
Industrial & Transportation[3]	-4	38	-68	34	-102	-47	-17	-88	0	0	0
Total Net Additions	**4,172**	**8,215**	**8,412**	**6,551**	**8,841**	**5,484**	**3,392**	**4,521**	**4,443**	**4,694**	**4,890**
Year-End Customers	543,026	551,241	559,653	566,204	575,045	580,529	583,921	588,442	592,885	597,579	602,469

Inland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	1,380	2,759	3,385	3,243	3,583	3,040	1,479	2,028	1,592	1,683	1,754
Commercial[2]	-13	349	299	286	186	342	87	110	69	69	69
Industrial & Transportation[3]	4	14	-22	5	-20	-8	-12	-6	0	0	0
Total Net Additions	**1,371**	**3,122**	**3,662**	**3,534**	**3,749**	**3,374**	**1,554**	**2,132**	**1,661**	**1,752**	**1,823**
Year-End Customers	210,029	213,151	216,813	220,347	224,096	227,470	229,024	231,156	232,817	234,569	236,392

Columbia Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	46	111	194	181	338	267	160	222	207	207	207
Commercial[2]	-28	22	21	11	14	46	-15	-2	3	3	3
Industrial & Transportation[3]	2	-4	-1	-1	-4	1	-2	-2	0	0	0
Total Net Additions	**20**	**129**	**214**	**191**	**348**	**314**	**143**	**218**	**210**	**210**	**210**
Year-End Customers	21,119	21,248	21,462	21,653	22,001	22,315	22,458	22,676	22,886	23,096	23,306

Revelstoke Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	-12	44	15	12	29	16	0	0	0	0	0
Commercial[2]	-3	10	1	3	2	11	1	-2	0	0	0
Total Net Additions	**-15**	**54**	**16**	**15**	**31**	**27**	**1**	**-2**	**0**	**0**	**0**
Year-End Customers	1,429	1,483	1,499	1,514	1,545	1,572	1,573	1,571	1,571	1,571	1,571

Mainland (Sum of Lower Mainland, Inland, Columbia and Revelstoke) :

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	6,306	10,716	11,427	9,595	12,003	7,959	4,822	6,824	6,165	6,507	6,774
Commercial[2]	-2,035	756	968	658	1,092	1,294	299	141	149	149	149
Industrial & Transportation[3]	2	48	-91	38	-126	-54	-31	-96	0	0	0
Total Net Additions	**4,273**	**11,520**	**12,304**	**10,291**	**12,969**	**9,199**	**5,090**	**6,869**	**6,314**	**6,656**	**6,923**
Year-End Customers	775,603	787,123	799,427	809,718	822,687	831,886	836,976	843,845	850,159	856,815	863,738

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[4]	2,556	3,951	2,723	3,798	3,757	3,326	2,785	2,350	2,328	2,463	2,564
Commercial[5]	6	212	-139	283	124	203	148	82	94	94	94
Transportation[6]	-	-	-	-	-	-	-	-	-	-	-
Total Net Additions	**2,562**	**4,163**	**2,584**	**4,081**	**3,881**	**3,529**	**2,933**	**2,432**	**2,422**	**2,557**	**2,658**
Year-End Customers	76,533	80,696	83,280	87,361	91,242	94,771	97,704	100,136	102,558	105,115	107,773

Whistler:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[7]				43	34	36	116	12	14	14	15
Commercial[8]				-3	7	10	7	0	4	5	4
Total Net Additions				**40**	**41**	**46**	**123**	**12**	**18**	**19**	**19**
Year-End Customers				2,370	2,411	2,457	2,580	2,592	2,610	2,629	2,648

Fort Nelson:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	100	52	26	3	7	-3	0	12	12	11	13
Commercial[9]	8	33	19	10	7	4	-2	9	11	11	11
Industrial[10]	-	-	-	-	-	-	-	-	-	-	-
Total Net Additions	**108**	**85**	**45**	**13**	**14**	**1**	**-2**	**21**	**23**	**22**	**24**
Year-End Customers	2,211	2,296	2,341	2,354	2,368	2,369	2,367	2,388	2,411	2,433	2,457

Notes:

1. Rate 1
2. Rates 2, 3, and 23
3. Rates 4, 5, 6, 7, 22, 25, and 27
4. RGS
5. AGS, SCS1, SCS2, LCS1, LCS2, LCS3, HLF, ILF
6. Rate 22
7. SGS Res
8. SGS Com, LGS1, LGS2, LGS3
9. Rates 2.1, 2.2
10. Rate 25

ACTUAL ENERGY DEMAND 2003 - 2010 (PJs)

Lower Mainland Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	50.7	48.4	51.1	51.3	56.2	58.8	53.2	48.7
Commercial[2]	32.2	32.2	33.4	33.8	37.3	38.6	38.3	35.0
Industrial[3]	34.4	31.2	32.5	31.4	30.4	29.7	27.8	27.4
Total	**117.3**	**111.8**	**117.0**	**116.5**	**123.9**	**127.1**	**119.3**	**111.1**

Inland Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	15.9	15.8	16.0	15.4	16.7	17.6	16.8	14.8
Commercial[2]	8.7	8.7	8.9	8.6	9.5	10.1	10.1	8.9
Industrial[3]	28.3	28.7	27.3	23.8	26.4	22.2	17.6	19.8
Total	**52.9**	**53.2**	**52.2**	**47.8**	**52.6**	**49.9**	**44.5**	**43.5**

Columbia Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	1.7	1.8	1.7	1.6	1.7	1.8	1.7	1.6
Commercial[2]	0.9	1.0	0.9	0.9	1.0	1.1	1.1	1.0
Industrial[3]	3.6	3.7	3.5	3.1	3.2	3.5	3.0	4.3
Total	**6.2**	**6.5**	**6.1**	**5.6**	**5.9**	**6.4**	**5.8**	**6.9**

Revelstoke Region:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial[2]	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

Mainland Consolidated - All Regions:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	68.4	66.1	68.9	68.4	74.7	78.3	71.8	65.2
Commercial[2]	41.9	42.1	43.3	43.4	47.9	49.9	49.6	45.0
Industrial[3]	66.2	63.6	63.3	58.3	60.0	55.3	48.4	51.5
Total	**176.5**	**171.8**	**175.5**	**170.1**	**182.6**	**183.5**	**169.8**	**161.7**

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[4]	4.0	3.8	4.2	4.5	4.7	5.0	4.9	4.5
Commercial[5]	7.2	7.0	7.3	7.3	7.6	7.6	7.4	6.9
Tranportation[6]	21.2	21.5	22.1	16.3	23.3	22.3	18.9	19.5
Total	**32.3**	**32.3**	**33.6**	**28.1**	**35.6**	**35.0**	**31.2**	**30.9**

Whistler

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[7]				0.2	0.2	0.2	0.2	0.2
Commercial[8]				0.5	0.5	0.5	0.5	0.5
Total				**0.7**	**0.7**	**0.7**	**0.7**	**0.7**

Fort Nelson:

	2003	2004	2005	2006	2007	2008	2009	2010
Residential[1]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial[9]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

NORMALIZED ACTUAL ENERGY DEMAND 2003 - 2013 (PJs)

Lower Mainland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	54.0	53.9	51.6	52.1	52.7	51.6	52.4	52.6	52.6	52.5	52.5
Commercial[2]	34.8	35.1	33.9	34.0	35.2	35.7	36.6	36.2	36.3	36.5	36.7
Industrial[3]	34.4	31.2	32.5	31.4	30.4	29.7	27.8	27.4	27.5	27.3	27.4
Total	**123.1**	**120.2**	**118.0**	**117.5**	**118.3**	**117.0**	**116.8**	**116.2**	**116.4**	**116.4**	**116.7**

Inland Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	16.7	16.4	15.9	16.1	16.1	15.5	15.9	15.8	15.7	15.6	15.6
Commercial[2]	9.4	9.0	8.8	9.0	9.2	9.0	9.4	9.3	9.3	9.4	9.4
Industrial[3]	28.3	28.7	27.3	23.8	26.4	22.2	17.6	19.8	19.6	20.1	20.0
Total	**54.4**	**54.0**	**52.0**	**48.9**	**51.7**	**46.7**	**42.8**	**44.9**	**44.6**	**45.1**	**45.0**

Columbia Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Commercial[2]	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Industrial[3]	3.6	3.7	3.5	3.1	3.2	3.5	3.0	4.3	4.1	4.2	4.2
Total	**6.4**	**6.4**	**6.1**	**5.7**	**6.0**	**6.2**	**5.8**	**7.0**	**6.8**	**6.9**	**6.9**

Revelstoke Region:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial[2]	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

Mainland Consolidated - All Regions:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	72.6	72.0	69.3	70.0	70.6	68.8	70.0	70.0	70.0	69.9	69.8
Commercial[2]	45.3	45.2	43.9	44.1	45.5	45.9	47.2	46.6	46.8	47.1	47.3
Industrial[3]	66.2	63.6	63.3	58.3	60.0	55.3	48.4	51.5	51.2	51.5	51.6
Total	**184.1**	**180.8**	**176.4**	**172.4**	**176.2**	**170.0**	**165.6**	**168.2**	**168.0**	**168.5**	**168.7**

Vancouver Island:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[4]	4.0	4.0	4.2	4.6	4.6	4.7	4.6	4.7	4.6	4.6	4.5
Commercial[5]	7.3	7.2	7.4	7.3	7.5	7.3	7.2	7.1	7.1	7.2	7.3
Tranportation[6]	21.2	21.5	22.1	16.3	23.3	22.3	18.9	19.5	22.3	22.3	22.3
Total	**32.5**	**32.8**	**33.8**	**28.3**	**35.4**	**34.4**	**30.7**	**31.3**	**34.0**	**34.1**	**34.2**

Whistler

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[7]				0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial[8]				0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total				**0.7**	**0.7**	**0.7**	**0.6**	**0.8**	**0.7**	**0.7**	**0.7**

Fort Nelson:

	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Residential[1]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial[9]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

WEATHER DATA 2003 - 2010

Annual Heating Degree Days, by Region

	2003	2004	2005	2006	2007	2008	2009	2010
Lower Mainland	2,667	2,525	2,664	2,714	2,889	3,043	2,921	2,621
Inland	3,684	3,631	3,702	3,637	3,778	4,093	4,077	3,646
Columbia	4,420	4,273	4,483	4,217	4,406	4,654	4,650	4,382
Revelstoke	3,982	4,004	3,987	3,833	4,124	4,226	4,098	3,729
Fort Nelson	6,601	6,805	6,211	6,607	6,796	6,887	7,132	6,444
Vancouver Island	2,797	2,663	2,769	2,793	2,952	3,163	3,048	2,854
Whistler	4,008	3,832	3,935	3,906	4,099	4,272	4,178	4,095

Notes:

1. Vancouver airport weather station

2 Simple average of the Castlegar, Kelowna, Penticton and Prince George airport weather stations

3. Cranbrook airport weather station

4. Revelstoke airport weather station

5. Heating degree days are b HDD18 = Maximum(0, 18 - Temperature)

6. Vancouver Island data from Finance

BC Housing Starts Forecast

	2010	2011	2012	2013
Single-Detached Housing Starts (Units)	11,462	11,300	11,900	12,368
Percent Change	45.2%	-1.4%	5.3%	3.9%
Multiple Housing Starts (Units)	15,017	15,600	17,100	18,123
Percent Change	83.5%	3.9%	9.6%	6.0%
Housing Starts Total	**26,479**	**26,900**	**29,000**	**30,490**

Sources: CMHC, The Conference Board of Canada

Appendix C-3

FORECASTING

REFER TO LIVE SPREADSHEETS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix D-1

HISTORIC DATA

1 HISTORIC DATA

This appendix includes the historic Operating and Maintenance expenses, a history of FTEs, historic data of the Utility Income and Earned Return, Income taxes, Return on Capital, Utility Rate Base, Capital Expenditure, and Customer Service Call Volume information.

2 OPERATING AND MAINTENANCE EXPENSE HISTORY

The following table illustrates the O&M expenses years 2006-2013 in Resource view. A detailed O&M expense schedule by Resource and Activity view per company is included in this appendix with all years restated to reflect the current organization structure.

Table D-1: O&M Resourse View, 2006-2013

FORTISBC ENERGY INC (COMBINED)
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	2006	2007	2008	2009	2010	Projection 2011	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	M&E Costs	$ 40,312	$ 44,601	$ 42,244	$ 44,495	$ 47,051	$ 52,316	$ 58,567	$ 60,697
2	COPE Costs	22,591	22,074	23,134	25,677	28,717	31,237	36,133	38,131
3	COPE Customer Services Costs							11,824	11,177
4	IBEW Costs	24,428	24,593	25,761	26,631	27,748	30,839	33,159	34,931
5									
6	**Labour Costs**	**87,331**	**91,268**	**91,138**	**96,803**	**103,516**	**114,391**	**139,683**	**144,935**
7									
8	Vehicle Costs	4,871	5,362	5,626	5,516	4,312	4,045	4,484	4,544
9	Employee Expenses	3,836	3,961	4,854	4,777	6,375	4,688	6,172	6,351
10	Materials and Supplies	5,021	5,556	6,844	7,123	7,878	6,593	8,117	8,490
11	Office Furnishing & Equipment	47	-	-	-	19			
12	Computer Costs	8,944	8,021	7,890	8,417	10,773	11,124	14,734	15,306
13	Fees and Administration Costs	42,476	33,862	36,689	34,359	41,131	40,383	74,264	79,629
14	Contractor Costs	57,763	59,169	62,484	64,806	68,661	69,807	23,920	26,386
15	Facilities	12,517	13,405	13,161	14,227	15,164	15,544	18,511	16,344
16	Recoveries & Revenue	(16,435)	(15,489)	(15,520)	(15,994)	(19,892)	(18,244)	(28,758)	(28,220)
17									
18	**Non-Labour Costs**	**119,040**	**113,846**	**122,029**	**123,231**	**134,422**	**133,942**	**121,444**	**128,831**
19									
20	**Total Gross O&M Expenses**	**206,371**	**205,115**	**213,167**	**220,034**	**237,938**	**248,333**	**261,127**	**273,766**
21									
22	Add: Shared Corporate Services								
23	Add: PST Savings						730		
24	Less: O&M Difference from Allowed	-	-	-	-	1,379			
25	Less: Vehicle Lease Reclass	(2,100)	(2,008)	(1,988)	(1,804)	-			
26	Less: Capitalized Overhead	(32,034)	(32,470)	(32,718)	(33,365)	(33,510)	(34,857)	(36,558)	(38,327)
27									
28	**Total O&M Expenses**	**$ 172,237**	**$ 170,637**	**$ 178,461**	**$ 184,865**	**$ 205,806**	**$ 214,206**	**$ 224,569**	**$ 235,438**

When the O&M expense is adjusted for inflation, the increase in FEU O&M per customer from 2006 through 2010 is virtually flat, increasing approximately 1.3% or an average of 0.3% per year over the five year period. The proposed O&M expense in 2013 results in an increase of approximately 6.8% or an average of less than 1% per year, when compared to 2006.

Table D-2: Nominal O&M per Customer is Stable

HISTORICAL AND FORECAST O&M EXPENSES BY CUSTOMER
($000)

	Actual					Projection	Forecast	Forecast
	2006	2007	2008	2009	2010	2011	2012	2013
FEU Total Gross Nominal O&M Expenses	$ 206,371	$ 205,115	$ 213,167	$ 220,034	$ 237,938	$ 249,063	$ 261,127	$ 273,765
FEU Total Gross Real O&M Expenses	$ 226,388	$ 221,523	$ 225,957	$ 228,396	$ 242,220	$ 249,063	$ 256,031	$ 263,075
FEU Average Number of Customers	893	910	923	934	943	953	962	971
FEU Nominal O&M per Customer	**$ 231**	**$ 225**	**$ 231**	**$ 236**	**$ 252**	**$ 261**	**$ 272**	**$ 282**
FEU Real O&M per Customer	**$ 254**	**$ 243**	**$ 245**	**$ 245**	**$ 257**	**$ 261**	**$ 266**	**$ 271**

The following is a list of the current Business Area structure in which O&M expenditures are categorized. Both Nominal and Real O&M Expenses, and O&M per Customer are included at the end of this Appendix.

Table D-3: Current Business Area Structure

Business Area
Distribution
Transmission
Energy Supply & Resource Development
Customer Service
Energy Solution & External Relations
Information Technology
Operations Engineering
Operations Support
Facilities
Human Resources
Environmental & Safety
Finance and Regulatory
Corporate

3 FTE HISTORY

FTE per Business Unit in each Company is included at the end of this appendix. The FTE information has been restated to reflect the current organization structure.

Table D-4: Combined History and Forecast FTE by Business Unit

FortisBC Energy Inc.
Combined - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	37	36	36	38	40	45	46	47
2	Facilities	12	13	10	10	13	17	18	18
3	Operations Engineering	113	119	134	143	153	178	193	193
4	Operations Support	131	129	129	124	125	133	139	142
5	Customer Service	31	23	22	25	32	367	325	309
6	Human Resources	77	75	78	93	96	70	71	72
7	Environmental & Safety	8	8	8	10	11	14	14	14
8	Information Technology	46	49	51	55	64	66	75	76
9	Distribution	543	547	565	559	579	658	660	669
10	Energy Solution & External Relations	65	66	64	74	96	118	125	125
11	Finance and Regulatory	61	60	65	67	65	68	69	69
12	Transmission	60	63	61	67	72	86	92	94
13	Corporate	2	2	2	2	2	1	1	1
14									
15	Total FTE	1,187	1,191	1,227	1,267	1,347	1,821	1,828	1,829
16									
17	Affiliation Summary								
18	COPE	416	421	431	441	464	759	754	749
19	IBEW	499	495	503	494	506	570	564	568
20	M&E	272	275	293	332	377	492	510	512
21	Total FTE	1,187	1,191	1,227	1,267	1,347	1,821	1,828	1,829

4 FINANCIAL SCHEDULES

Historic data from 2006-2010 is provided, which includes Utility Income and Earned Return, Income taxes, Return on Capital, and Utility Rate Base per company. The consolidated view of FEU for the historic period is a summation of the individual Utilities without amalgamation adjustments. Amalgamation adjustments are discussed in Section 3 of the Application.

5 CAPITAL EXPENDITURES

Base capital expenditures and additions are provided per company from years 2006-2010.

6 CUSTOMER SERVICE DEPARTMENT

Actual call volumes for the Contact Centre is provided for the years 2008-2010.

7 ATTACHEMENTS

The following attachments are included with this appendix:

1. Historic and Forecast Operating and Maintenance Expense both in Resource and Activity view per company and combined.
2. Historic and Forecast Operating and Maintenance Expense by Business Unit per company.
3. Historic and Forecast FTE by Business Unit and Affiliation per company.
4. Historic Financial Summaries of Utility Income and Earned Return, Income taxes, Return on Capital, and Utility Rate Base per company.
5. Historic Capital Expenditure per company.
6. Customer Service Call Volume Data.

Appendix D-2

HISTORIC AND FORECAST O&M ACTIVITY RESOURCE

FORTISBC ENERGY INC (COMBINED)
2006 OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 36,995	$ 3,083	$ 63	$ 172		$ 40,312
2	COPE Costs	22,382	136		74		22,591
3	IBEW Costs	18,559	5,483	183	203		24,428
4							-
5	**Labour Costs**	**77,936**	**8,701**	**245**	**449**	**-**	**87,331**
6							
7	Vehicle Costs	4,226	571	35	39		4,871
8	Employee Expenses	3,378	414	14	31		3,836
9	Materials and Supplies	4,223	758	15	25		5,021
10	Office Furnishing & Equipment	-	47	-	-		47
11	Computer Costs	8,086	825	0	33		8,944
12	Fees and Administration Costs	33,884	8,199	285	108		42,476
13	Contractor Costs	52,298	5,251	55	159		57,763
14	Facilities	10,012	2,286	185	34		12,517
15	Recoveries & Revenue	(14,836)	(1,528)	(13)	(58)		(16,435)
16							
17	**Non-Labour Costs**	**101,270**	**16,823**	**576**	**371**	**-**	**119,040**
18							
19	**Total Gross O&M Expenses**	**179,206**	**25,524**	**821**	**820**	**-**	**206,371**
20							
21	Less: Vehicle Lease Reclass	(1,872)	(228)	-	-		(2,100)
22	Less: Capitalized Overhead	(27,111)	(4,695)	(96)	(132)		(32,034)
23							
24	**Total O&M Expenses**	**$ 150,223**	**$ 20,601**	**$ 725**	**$ 688**	**$ -**	**$ 172,237**

FORTISBC ENERGY INC (COMBINED)
2007 OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 41,161	$ 3,204	$ 64	$ 172		$ 44,601
2	COPE Costs	21,966	47	-	61		22,074
3	IBEW Costs	19,926	4,223	202	242		24,593
4							-
5	**Labour Costs**	**83,053**	**7,474**	**266**	**475**	**-**	**91,268**
6							
7	Vehicle Costs	4,748	534	28	52		5,362
8	Employee Expenses	3,498	424	7	32		3,961
9	Materials and Supplies	4,436	1,080	17	23		5,556
10	Office Furnishing & Equipment	-	-	-	-		-
11	Computer Costs	7,489	501	1	30		8,021
12	Fees and Administration Costs	25,246	8,239	299	78		33,862
13	Contractor Costs	53,640	5,319	49	161		59,169
14	Facilities	10,921	2,313	134	37		13,405
15	Recoveries & Revenue	(14,058)	(1,370)	(8)	(53)		(15,489)
16							
17	**Non-Labour Costs**	**95,919**	**17,040**	**527**	**360**	**-**	**113,846**
18							
19	**Total Gross O&M Expenses**	**178,973**	**24,514**	**793**	**835**	**-**	**205,115**
20							
21	Less: Vehicle Lease Reclass	(2,008)	-	-	-		(2,008)
22	Less: Capitalized Overhead	(27,401)	(4,839)	(96)	(134)		(32,470)
23							
24	**Total O&M Expenses**	**$ 149,564**	**$ 19,675**	**$ 697**	**$ 701**	**$ -**	**$ 170,637**

FORTISBC ENERGY INC (COMBINED)
2008 OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 38,581	$ 3,466	$ 72	$ 125		$ 42,244
2	COPE Costs	23,046	39	2	47		23,134
3	IBEW Costs	21,201	4,113	209	238		25,761
4							-
5	**Labour Costs**	**82,827**	**7,618**	**283**	**410**	**-**	**91,138**
6							
7	Vehicle Costs	5,001	543	27	55		5,626
8	Employee Expenses	4,422	399	18	15		4,854
9	Materials and Supplies	5,891	919	19	15		6,844
10	Office Furnishing & Equipment	-	-	-	-		-
11	Computer Costs	7,391	477	-	22		7,890
12	Fees and Administration Costs	27,976	8,285	363	65		36,689
13	Contractor Costs	55,593	6,670	63	158		62,484
14	Facilities	10,792	2,182	153	34		13,161
15	Recoveries & Revenue	(14,155)	(1,311)	(20)	(34)		(15,520)
16							
17	**Non-Labour Costs**	**102,912**	**18,164**	**623**	**330**	**-**	**122,029**
18							
19	**Total Gross O&M Expenses**	**185,739**	**25,782**	**906**	**740**	**-**	**213,167**
20							
21	Less: Vehicle Lease Reclass	(1,988)	-	-	-		(1,988)
22	Less: Capitalized Overhead	(27,543)	(4,936)	(98)	(141)		(32,718)
23							
24	**Total O&M Expenses**	**$ 156,208**	**$ 20,846**	**$ 808**	**$ 599**	**$ -**	**$ 178,461**

FORTISBC ENERGY INC (COMBINED)
2009 OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 40,725	$ 3,564	$ 78	$ 128		$ 44,495
2	COPE Costs	25,571	48	3	55		25,677
3	IBEW Costs	22,397	3,756	216	262		26,631
4							-
5	**Labour Costs**	**88,693**	**7,368**	**297**	**445**	**-**	**96,803**
6							
7	Vehicle Costs	4,926	486	39	65		5,516
8	Employee Expenses	4,254	491	19	13		4,777
9	Materials and Supplies	5,779	1,314	16	14		7,123
10	Office Furnishing & Equipment	-	-	-	-		-
11	Computer Costs	7,975	418	-	24		8,417
12	Fees and Administration Costs	25,122	8,897	283	57		34,359
13	Contractor Costs	58,092	6,519	27	168		64,806
14	Facilities	11,974	2,084	130	39		14,227
15	Recoveries & Revenue	(14,870)	(1,063)	(20)	(41)		(15,994)
16							
17	**Non-Labour Costs**	**103,252**	**19,146**	**494**	**339**	**-**	**123,231**
18							
19	**Total Gross O&M Expenses**	**191,945**	**26,514**	**791**	**784**	**-**	**220,034**
20							
21	Less: Vehicle Lease Reclass	(1,804)	-	-	-		(1,804)
22	Less: Capitalized Overhead	(28,115)	(5,033)	(91)	(126)		(33,365)
23							
24	**Total O&M Expenses**	**$ 162,026**	**$ 21,481**	**$ 700**	**$ 658**	**$ -**	**$ 184,865**

FORTISBC ENERGY INC (COMBINED)
2010 OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 43,296	$ 3,570	$ 59	$ 126		$ 47,051
2	COPE Costs	28,413	248	1	55		28,717
3	IBEW Costs	22,625	4,644	212	267		27,748
4							-
5	**Labour Costs**	**94,334**	**8,462**	**272**	**448**	**-**	**103,516**
6							
7	Vehicle Costs	3,625	606	28	52		4,312
8	Employee Expenses	5,805	568	(17)	19		6,375
9	Materials and Supplies	6,738	1,103	21	16		7,878
10	Office Furnishing & Equipment		19				19
11	Computer Costs	10,214	529	1	29		10,773
12	Fees and Administration Costs	29,309	11,465	289	68		41,131
13	Contractor Costs	62,151	6,205	133	172		68,661
14	Facilities	13,023	2,047	59	35		15,164
15	Recoveries & Revenue	(18,680)	(1,153)	(14)	(45)		(19,892)
16							
17	**Non-Labour Costs**	**112,185**	**21,390**	**501**	**346**	**-**	**134,422**
18							
19	**Total Gross O&M Expenses**	**206,519**	**29,852**	**773**	**794**	**-**	**237,938**
20							
21	Less: O&M Difference from Allowed		1,379				1,379
22	Less: Vehicle Lease Reclass						-
23	Less: Capitalized Overhead	(28,905)	(4,372)	(119)	(114)		(33,510)
24							
25	**Total O&M Expenses**	**$ 177,614**	**$ 26,859**	**$ 654**	**$ 680**	**$ -**	**$ 205,806**

FORTISBC ENERGY INC (COMBINED)
2006 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 7,344	$ 2,107	$ 164	$ 81		$ 9,695
2	Distribution Supervision Total	100-10	7,344	2,107	164	81	-	9,695
3	Operation Centre - Distribution	100-21	6,379	0		67		6,445
4	Asset Management - Distribution	100-22	1,400			15		1,415
5	Preventative Maintenance - Distribution	100-23	1,556	193	9	16		1,774
6	Distribution Operations - General	100-24	3,707	1,357	266	39		5,369
7	Emergency Management	100-25	5,527	1,341	49	58		6,974
8	Distribution Operations Total	100-20	18,568	2,891	324	194	-	21,978
9	Distribution Corrective - Meters	100-31	937	145	4	10		1,096
10	Distribution Corrective - Propane	100-32	3	-	44	0		46
11	Distribution Corrective - Leak Repair	100-33	848	84	1	9		942
12	Distribution Corrective - Stations	100-34	427	18	1	4		450
13	Distribution Corrective - General	100-35	404	65	0	4		473
14	Distribution Maintenance Total	100-30	2,619	313	49	27	-	3,008
15	**Distribution Total**	**100**	**28,531**	**5,311**	**538**	**302**	**-**	**34,681**
16	Transmission Supervision	200-11	1,889					1,889
17	Transmission Supervision Total	200-10	1,889	-	-	-	-	1,889
18	Pipeline Operation	200-21	962	827				1,789
19	Right of Way	200-22	1,677	263				1,939
20	Compression	200-23	1,585	744				2,329
21	Gas Control	200-24	1,939	-				1,939
22	Transmission Pipeline Integrity Project (TPIP)	200-25	4,065					4,065
23	Transmission Operations Total	200-20	10,228	1,834	-	-	-	12,062
24	Pipeline - Maintenance	200-31	211	427				639
25	Compression - Maintenance	200-32	157	1,140				1,296
26	TPIP - Maintenance	200-33	435					435
27	Transmission Maintenance Total	200-30	803	1,567	-	-	-	2,370
28	**Transmission Total**	**200**	**12,920**	**3,401**	**-**	**-**	**-**	**16,322**
29	LNG Plant Operations	300-11	524					524
30	LNG Plant Operations Total	300-10	524	-	-	-	-	524
31	LNG Plant Maintenance	300-21	291					291
32	LNG Plant Maintenance Total	300-20	291	-	-	-	-	291
33	**LNG Plant Total**	**300**	**815**	**-**	**-**	**-**	**-**	**815**
34	Measurement Operations	400-11	3,159	465	9			3,633
35	Measurement Operations Total	400-10	3,159	465	9	-	-	3,633
36	Measurement Maintenance	400-21	2,899	505				3,404
37	Measurement Maintenance Total	400-20	2,899	505	-	-	-	3,404
38	**Measurement Total**	**400**	**6,059**	**970**	**9**	**-**	**-**	**7,037**
39	Facilities Management	500-10	5,074	1,442				6,516
40	Shops & Stores	500-20	2,807					2,807
41	Operations Engineering	500-30	5,509	283				5,791
42	Property Services	500-40	881					881
43	System Integrity	500-50	1,904	77				1,981
44	Environmental Health & Safety	500-60	1,162					1,162
45	Operations Governance	500-70	1,159					1,159
			-					-
46	**General Operations Total**	**500**	**18,496**	**1,802**	**-**	**-**	**-**	**20,298**

FORTISBC ENERGY INC (COMBINED)
2006 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10	$ 1,556					$ 1,556
2	Marketing - Supervision	600-20	562					562
3	Corporate & Marketing Communications	600-30	2,853	687				3,540
4	Marketing Planning & Development	600-40	686					686
5	**Marketing Total**	**600**	**5,656**	**687**	**-**	**-**	**-**	**6,344**
6	Customer Care - Supervision	700-10	735	0				735
7	Customer Contact - ABSU contract	700-20	44,168	4,868	23	130		49,190
8	Bad Debt Management and Administration	700-30	10,743	105	5			10,853
9	Customer Management & Sales	700-40	2,361	913				3,274
10	**Customer Care Total**	**700**	**58,007**	**5,887**	**28**	**130**	**-**	**64,052**
11	Business & IT Services - Supervision	800-10	1,858					1,858
12	Application Management	800-20	6,183	493				6,676
13	Infrastructure Management	800-30	5,472					5,472
14	Procurement Services	800-40	674					674
15	**Business & IT Services Total**	**800**	**14,188**	**493**	**-**	**-**	**-**	**14,681**
16	Administration & General	900-11	2,176	770	18	388		3,352
17	Insurance	900-12	5,085	649				5,734
18	Finance and Regulatory Affairs	900-13	7,265	254				7,519
19	Shared Services Agreement	900-14	4,035	4,745				8,780
20	Corporate Administration Total	900-10	18,561	6,418	18	388	-	25,385
21	Forecasting	900-20	1,184					1,184
22	Public Affairs	900-30	1,359	109				1,468
23	Business Development	900-40	1,194					1,194
24	Human Resources	900-50	4,027	13				4,041
25	Other Post Employment Benefits (OPEB)	900-60	8,208	662				8,870
26	**Administration & General Total**	**900**	**34,533**	**7,202**	**18**	**388**	**-**	**42,141**
27	**Total Gross O&M Expenses**		**179,206**	**25,752**	**593**	**820**	**-**	**206,371**
28	Less: Vehicle Lease Reclass		(1,872)	(228)	-			(2,100)
29	Less: Capitalized Overhead		(27,111)	(4,695)	(96)	(132)		(32,034)
30	**Total O&M Expenses**		**$ 150,223**	**$ 20,829**	**$ 497**	**$ 688**	**$ -**	**$ 172,237**

FORTISBC ENERGY INC (COMBINED)
2007 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 8,875	$ 1,641	$ 163	$ 90		$ 10,769
2	Distribution Supervision Total	100-10	8,875	1,641	163	90	-	10,769
3	Operation Centre - Distribution	100-21	6,126	-	-	61		6,187
4	Asset Management - Distribution	100-22	960	-	-	10		970
5	Preventative Maintenance - Distribution	100-23	1,501	273	21	15		1,810
6	Distribution Operations - General	100-24	4,398	923	215	44		5,580
7	Emergency Management	100-25	5,678	907	41	75		6,701
8	Distribution Operations Total	100-20	18,663	2,103	277	205	-	21,248
9	Distribution Corrective - Meters	100-31	1,103	233	9	11		1,356
10	Distribution Corrective - Propane	100-32	7	-	29	0		36
11	Distribution Corrective - Leak Repair	100-33	1,017	151	2	10		1,180
12	Distribution Corrective - Stations	100-34	563	27	3	6		598
13	Distribution Corrective - General	100-35	359	83	-	4		445
14	Distribution Maintenance Total	100-30	3,049	494	43	30	-	3,616
15	**Distribution Total**	**100**	**30,587**	**4,238**	**483**	**326**	**-**	**35,633**
16	Transmission Supervision	200-11	2,194					2,194
17	Transmission Supervision Total	200-10	2,194	-	-	-	-	2,194
18	Pipeline Operation	200-21	1,784	1,076				2,860
19	Right of Way	200-22	1,220	166				1,386
20	Compression	200-23	1,536	853				2,389
21	Gas Control	200-24	1,848	-				1,848
22	Transmission Pipeline Integrity Project (TPIP)	200-25	3,284	-				3,284
23	Transmission Operations Total	200-20	9,672	2,095	-	-	-	11,767
24	Pipeline - Maintenance	200-31	47	205				252
25	Compression - Maintenance	200-32	100	872				972
26	TPIP - Maintenance	200-33	877	-				877
27	Transmission Maintenance Total	200-30	1,024	1,077	-	-	-	2,101
28	**Transmission Total**	**200**	**12,890**	**3,172**	**-**	**-**	**-**	**16,062**
29	LNG Plant Operations	300-11	781					781
30	LNG Plant Operations Total	300-10	781	-	-	-	-	781
31	LNG Plant Maintenance	300-21	198					198
32	LNG Plant Maintenance Total	300-20	198	-	-	-	-	198
33	**LNG Plant Total**	**300**	**980**	**-**	**-**	**-**	**-**	**980**
34	Measurement Operations	400-11	3,356	581	18			3,955
35	Measurement Operations Total	400-10	3,356	581	18	-	-	3,955
36	Measurement Maintenance	400-21	1,870	456				2,326
37	Measurement Maintenance Total	400-20	1,870	456	-	-	-	2,326
38	**Measurement Total**	**400**	**5,226**	**1,037**	**18**	**-**	**-**	**6,281**
39	Facilities Management	500-10	4,857	1,409				6,266
40	Shops & Stores	500-20	3,233	-				3,233
41	Operations Engineering	500-30	5,931	212				6,143
42	Property Services	500-40	760	-				760
43	System Integrity	500-50	2,005	136				2,141
44	Environmental Health & Safety	500-60	1,066	-				1,066
45	Operations Governance	500-70	1,351	-				1,351
			-					-
46	**General Operations Total**	**500**	**19,203**	**1,757**	**-**	**-**	**-**	**20,960**

FORTISBC ENERGY INC (COMBINED)
2007 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)		(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10	$ 1,599					$ 1,599
2	Marketing - Supervision	600-20	1,174					1,174
3	Corporate & Marketing Communications	600-30	2,156	377				2,533
4	Marketing Planning & Development	600-40	607					607
5	**Marketing Total**	**600**	**5,536**	**377**	**-**	**-**	**-**	**5,913**
6	Customer Care - Supervision	700-10	724					724
7	Customer Contact - ABSU contract	700-20	45,366	4,462	24	130		49,982
8	Bad Debt Management and Administration	700-30	4,521	395	11			4,927
9	Customer Management & Sales	700-40	2,484	972				3,456
10	**Customer Care Total**	**700**	**53,094**	**5,829**	**35**	**130**	**-**	**59,088**
11	Business & IT Services - Supervision	800-10	1,857					1,857
12	Application Management	800-20	7,687	485				8,172
13	Infrastructure Management	800-30	5,675					5,675
14	Procurement Services	800-40	681					681
15	**Business & IT Services Total**	**800**	**15,901**	**485**	**-**	**-**	**-**	**16,386**
16	Administration & General	900-11	2,012	611	23	380		3,025
17	Insurance	900-12	5,078	719				5,797
18	Finance and Regulatory Affairs	900-13	7,929	260				8,189
19	Shared Services Agreement	900-14	4,144	4,790	234			9,168
20	Corporate Administration Total	900-10	19,163	6,380	257	380	-	26,180
21	Forecasting	900-20	1,025					1,025
22	Public Affairs	900-30	1,373	164				1,537
23	Business Development	900-40	982					982
24	Human Resources	900-50	4,724					4,724
25	Other Post Employment Benefits (OPEB)	900-60	8,289	1,075				9,364
26	**Administration & General Total**	**900**	**35,556**	**7,619**	**257**	**380**	**-**	**43,812**
27	**Total Gross O&M Expenses**		**178,972**	**24,514**	**793**	**835**	**-**	**205,115**
28	Less: Vehicle Lease Reclass		(2,008)	-	-			(2,008)
29	Less: Capitalized Overhead		(27,401)	(4,839)	(96)	(134)		(32,470)
30	**Total O&M Expenses**		**$ 149,563**	**$ 19,675**	**$ 697**	**$ 701**	**$ -**	**$ 170,637**

FORTISBC ENERGY INC (COMBINED)
2008 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 9,133	$ 1,567	$ 185	$ 86		$ 10,970
2	Distribution Supervision Total	100-10	9,133	1,567	185	86	-	10,970
3	Operation Centre - Distribution	100-21	6,462	(5)	-	57		6,514
4	Asset Management - Distribution	100-22	1,043	-	-	9		1,052
5	Preventative Maintenance - Distribution	100-23	2,221	223	23	20		2,486
6	Distribution Operations - General	100-24	4,848	796	257	43		5,944
7	Emergency Management	100-25	6,417	1,313	51	74		7,855
8	Distribution Operations Total	100-20	20,990	2,327	331	202	-	23,851
9	Distribution Corrective - Meters	100-31	1,295	116	8	11		1,431
10	Distribution Corrective - Propane	100-32	4	-	33	0		37
11	Distribution Corrective - Leak Repair	100-33	990	131	7	9		1,136
12	Distribution Corrective - Stations	100-34	734	26	1	6		768
13	Distribution Corrective - General	100-35	327	66	-	3		396
14	Distribution Maintenance Total	100-30	3,350	339	49	30	-	3,767
15	**Distribution Total**	**100**	**33,473**	**4,233**	**565**	**317**	**-**	**38,588**
16	Transmission Supervision	200-11	1,841					1,841
17	Transmission Supervision Total	200-10	1,841	-	-	-	-	1,841
18	Pipeline Operation	200-21	2,212	1,366				3,578
19	Right of Way	200-22	1,363	151				1,514
20	Compression	200-23	1,451	777				2,228
21	Gas Control	200-24	1,909	(4)				1,905
22	Transmission Pipeline Integrity Project (TPIP)	200-25	4,202	-				4,202
23	Transmission Operations Total	200-20	11,137	2,290	-	-	-	13,427
24	Pipeline - Maintenance	200-31	128	355				483
25	Compression - Maintenance	200-32	202	1,510				1,712
26	TPIP - Maintenance	200-33	338	-				338
27	Transmission Maintenance Total	200-30	668	1,865	-	-	-	2,533
28	**Transmission Total**	**200**	**13,646**	**4,155**	**-**	**-**	**-**	**17,801**
29	LNG Plant Operations	300-11	720					720
30	LNG Plant Operations Total	300-10	720	-	-	-	-	720
31	LNG Plant Maintenance	300-21	254					254
32	LNG Plant Maintenance Total	300-20	254	-	-	-	-	254
33	**LNG Plant Total**	**300**	**974**	**-**	**-**	**-**	**-**	**974**
34	Measurement Operations	400-11	3,346	429	13			3,788
35	Measurement Operations Total	400-10	3,346	429	13	-	-	3,788
36	Measurement Maintenance	400-21	1,929	359				2,288
37	Measurement Maintenance Total	400-20	1,929	359	-	-	-	2,288
38	**Measurement Total**	**400**	**5,274**	**788**	**13**	**-**	**-**	**6,075**
39	Facilities Management	500-10	5,389	1,424				6,813
40	Shops & Stores	500-20	3,405	-				3,405
41	Operations Engineering	500-30	6,032	256				6,288
42	Property Services	500-40	1,011	-				1,011
43	System Integrity	500-50	2,042	201				2,243
44	Environmental Health & Safety	500-60	1,191	-				1,191
45	Operations Governance	500-70	1,464	-				1,464
			-					-
46	**General Operations Total**	**500**	**20,535**	**1,881**	**-**	**-**	**-**	**22,416**

FORTISBC ENERGY INC (COMBINED)
2008 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10	$ 1,740					$ 1,740
2	Marketing - Supervision	600-20	553					553
3	Corporate & Marketing Communications	600-30	2,695	452				3,147
4	Marketing Planning & Development	600-40	568					568
5	**Marketing Total**	**600**	**5,557**	**452**	**-**	**-**	**-**	**6,009**
6	Customer Care - Supervision	700-10	878					878
7	Customer Contact - ABSU contract	700-20	46,426	4,547	23	132		51,128
8	Bad Debt Management and Administration	700-30	5,022	412	12			5,446
9	Customer Management & Sales	700-40	3,108	1,087				4,195
10	**Customer Care Total**	**700**	**55,434**	**6,046**	**35**	**132**	**-**	**61,647**
11	Business & IT Services - Supervision	800-10	1,011					1,011
12	Application Management	800-20	7,861	452				8,313
13	Infrastructure Management	800-30	5,270					5,270
14	Procurement Services	800-40	670					670
15	**Business & IT Services Total**	**800**	**14,812**	**452**	**-**	**-**	**-**	**15,264**
16	Administration & General	900-11	3,446	586	53	290		4,375
17	Insurance	900-12	4,661	719				5,380
18	Finance and Regulatory Affairs	900-13	8,670	302				8,972
19	Shared Services Agreement	900-14	3,613	4,915	240			8,768
20	Corporate Administration Total	900-10	20,390	6,522	293	290	-	27,496
21	Forecasting	900-20	934					934
22	Public Affairs	900-30	1,394	173				1,567
23	Business Development	900-40	1,017					1,017
24	Human Resources	900-50	4,540					4,540
25	Other Post Employment Benefits (OPEB)	900-60	7,761	1,080				8,841
26	**Administration & General Total**	**900**	**36,036**	**7,775**	**293**	**290**	**-**	**44,394**
27	**Total Gross O&M Expenses**		**185,739**	**25,782**	**906**	**740**	**-**	**213,167**
28	Less: Vehicle Lease Reclass		(1,988)	-	-			(1,988)
29	Less: Capitalized Overhead		(27,543)	(4,936)	(98)	(141)		(32,718)
30	**Total O&M Expenses**		**$ 156,208**	**$ 20,846**	**$ 808**	**$ 599**	**$ -**	**$ 178,461**

FORTISBC ENERGY INC (COMBINED)
2009 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 9,803	$ 1,578	$ 209	$ 98		$ 11,688
2	Distribution Supervision Total	100-10	9,803	1,578	209	98	-	11,688
3	Operation Centre - Distribution	100-21	6,492	-	-	64		6,556
4	Asset Management - Distribution	100-22	1,106	239	-	10		1,355
5	Preventative Maintenance - Distribution	100-23	2,176	937	11	22		3,146
6	Distribution Operations - General	100-24	5,212	-	168	52		5,432
7	Emergency Management	100-25	6,093	1,059	64	61		7,277
8	Distribution Operations Total	100-20	21,079	2,235	243	209	-	23,766
9	Distribution Corrective - Meters	100-31	1,355	171	14	14		1,554
10	Distribution Corrective - Propane	100-32	-	-	21	0		21
11	Distribution Corrective - Leak Repair	100-33	1,098	82	4	11		1,195
12	Distribution Corrective - Stations	100-34	624	16	1	6		647
13	Distribution Corrective - General	100-35	277	30	-	3		310
14	Distribution Maintenance Total	100-30	3,354	299	40	34	-	3,727
15	**Distribution Total**	**100**	**34,236**	**4,112**	**492**	**341**	**-**	**39,181**
16	Transmission Supervision	200-11	2,924					2,924
17	Transmission Supervision Total	200-10	2,924	-	-	-	-	2,924
18	Pipeline Operation	200-21	2,417	2,132				4,549
19	Right of Way	200-22	1,435	131				1,566
20	Compression	200-23	1,629	822				2,451
21	Gas Control	200-24	2,471	-				2,471
22	Transmission Pipeline Integrity Project (TPIP)	200-25	4,285	-				4,285
23	Transmission Operations Total	200-20	12,237	3,085	-	-	-	15,322
24	Pipeline - Maintenance	200-31	122	377				499
25	Compression - Maintenance	200-32	241	832				1,073
26	TPIP - Maintenance	200-33	899	-				899
27	Transmission Maintenance Total	200-30	1,262	1,209	-	-	-	2,471
28	**Transmission Total**	**200**	**16,423**	**4,294**	**-**	**-**	**-**	**20,717**
29	LNG Plant Operations	300-11	844	1				845
30	LNG Plant Operations Total	300-10	844	1	-	-	-	845
31	LNG Plant Maintenance	300-21	255					255
32	LNG Plant Maintenance Total	300-20	255	-	-	-	-	255
33	**LNG Plant Total**	**300**	**1,099**	**1**	**-**	**-**	**-**	**1,100**
34	Measurement Operations	400-11	3,598	534	10			4,142
35	Measurement Operations Total	400-10	3,598	534	10	-	-	4,142
36	Measurement Maintenance	400-21	2,037	359				2,396
37	Measurement Maintenance Total	400-20	2,037	359	-	-	-	2,396
38	**Measurement Total**	**400**	**5,635**	**893**	**10**	**-**	**-**	**6,538**
39	Facilities Management	500-10	6,024	1,521				7,545
40	Shops & Stores	500-20	3,747	-				3,747
41	Operations Engineering	500-30	6,675	255				6,930
42	Property Services	500-40	991	-				991
43	System Integrity	500-50	2,214	201				2,415
44	Environmental Health & Safety	500-60	1,457	-				1,457
45	Operations Governance	500-70	1,445	-				1,445
			-					-
46	**General Operations Total**	**500**	**22,553**	**1,977**	**-**	**-**	**-**	**24,530**

FORTISBC ENERGY INC (COMBINED)
2009 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10	$ 1,624					$ 1,624
2	Marketing - Supervision	600-20	1,326					1,326
3	Corporate & Marketing Communications	600-30	2,765	361				3,126
4	Marketing Planning & Development	600-40	565					565
5	**Marketing Total**	**600**	**6,280**	**361**	**-**	**-**	**-**	**6,641**
6	Customer Care - Supervision	700-10	1,474					1,474
7	Customer Contact - ABSU contract	700-20	46,535	4,635	23	132		51,325
8	Bad Debt Management and Administration	700-30	5,804	431	20			6,255
9	Customer Management & Sales	700-40	3,396	882				4,278
10	**Customer Care Total**	**700**	**57,209**	**5,948**	**43**	**132**	**-**	**63,332**
11	Business & IT Services - Supervision	800-10	1,568					1,568
12	Application Management	800-20	9,190	420				9,610
13	Infrastructure Management	800-30	5,494					5,494
14	Procurement Services	800-40	700					700
15	**Business & IT Services Total**	**800**	**16,952**	**420**	**-**	**-**	**-**	**17,372**
16	Administration & General	900-11	163	248	1	311		723
17	Insurance	900-12	4,725	719				5,444
18	Finance and Regulatory Affairs	900-13	9,570	312				9,882
19	Shared Services Agreement	900-14	2,796	5,968	245			9,009
20	Corporate Administration Total	900-10	17,254	7,247	246	311	-	25,058
21	Forecasting	900-20	968					968
22	Public Affairs	900-30	1,659	224				1,883
23	Business Development	900-40	1,253					1,253
24	Human Resources	900-50	5,519					5,519
25	Other Post Employment Benefits (OPEB)	900-60	4,905	1,037				5,942
26	**Administration & General Total**	**900**	**31,558**	**8,508**	**246**	**311**	**-**	**40,623**
27	**Total Gross O&M Expenses**		**191,945**	**26,514**	**791**	**784**	**-**	**220,034**
28	Less: O&M Difference from Allowed							-
29	Less: Vehicle Lease Reclass		(1,804)	-				(1,804)
30	Less: Capitalized Overhead		(28,115)	(5,033)	(91)	(126)		(33,365)
31	**Total O&M Expenses**		**$ 162,026**	**$ 21,481**	**$ 700**	**$ 658**	**$ -**	**$ 184,865**

FORTISBC ENERGY INC (COMBINED)
2010 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	100-11	$ 9,763	$ 1,827	$ 170	$ 86		$ 11,846
2	Distribution Supervision Total	100-10	9,763	1,827	170	86	-	11,846
3	Operation Centre - Distribution	100-21	10,552	443	11	93		11,099
4	Asset Management - Distribution	100-22	1,747			15		1,762
5	Preventative Maintenance - Distribution	100-23	2,105	193	7	19		2,324
6	Distribution Operations - General	100-24	5,609	1,069	64	49		6,790
7	Emergency Management	100-25	4,528	820	57	40		5,445
8	Distribution Operations Total	100-20	24,541	2,525	138	216	-	27,421
9	Distribution Corrective - Meters	100-31	1,763	301	23	16		2,102
10	Distribution Corrective - Propane	100-32	-		2	-		2
11	Distribution Corrective - Leak Repair	100-33	1,331	86	17	12		1,445
12	Distribution Corrective - Stations	100-34	622	13	4	5		643
13	Distribution Corrective - General	100-35	393	68	2	3		466
14	Distribution Maintenance Total	100-30	4,109	467	46	36	-	4,659
15	**Distribution Total**	**100**	**38,413**	**4,819**	**354**	**338**	**-**	**43,925**
16	Transmission Supervision	200-11	3,205					3,205
17	Transmission Supervision Total	200-10	3,205	-	-	-	-	3,205
18	Pipeline Operation	200-21	2,135	1,316				3,451
19	Right of Way	200-22	1,592	114				1,706
20	Compression	200-23	1,981	919				2,900
21	Gas Control	200-24	2,611					2,611
22	Transmission Pipeline Integrity Project (TPIP)	200-25	2,722					2,722
23	Transmission Operations Total	200-20	11,041	2,350	-	-	-	13,391
24	Pipeline - Maintenance	200-31	220	490				710
25	Compression - Maintenance	200-32	242	716				958
26	TPIP - Maintenance	200-33	869					869
27	Transmission Maintenance Total	200-30	1,331	1,206	-	-	-	2,537
28	**Transmission Total**	**200**	**15,577**	**3,555**	**-**	**-**	**-**	**19,132**
29	LNG Plant Operations	300-11	930	438				1,368
30	LNG Plant Operations Total	300-10	930	438	-	-	-	1,368
31	LNG Plant Maintenance	300-21	431					431
32	LNG Plant Maintenance Total	300-20	431	-	-	-	-	431
33	**LNG Plant Total**	**300**	**1,361**	**438**	**-**	**-**	**-**	**1,799**
34	Measurement Operations	400-11	4,125	459	9			4,594
35	Measurement Operations Total	400-10	4,125	459	9	-	-	4,594
36	Measurement Maintenance	400-21	1,740	457				2,197
37	Measurement Maintenance Total	400-20	1,740	457	-	-	-	2,197
38	**Measurement Total**	**400**	**5,865**	**917**	**9**	**-**	**-**	**6,791**
39	Facilities Management	500-10	6,506	1,460				7,966
40	Shops & Stores	500-20	4,016					4,016
41	Operations Engineering	500-30	8,317	750				9,067
42	Property Services	500-40	1,204					1,204
43	System Integrity	500-50	2,330	119				2,449
44	Environmental Health & Safety	500-60	2,365					2,365
45	Operations Governance	500-70	1,660					1,660
								-
46	**General Operations Total**	**500**	**26,398**	**2,329**	**-**	**-**	**-**	**28,727**

FORTISBC ENERGY INC (COMBINED)
2010 OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	FEI	FEVI	FEW	Fort Nelson	Adjustments	Combined
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Efficiency	600-10	$ (7)					$ (7)
2	Marketing - Supervision	600-20	780					780
3	Corporate & Marketing Communications	600-30	3,133	137				3,270
4	Marketing Planning & Development	600-40	626					626
5	**Marketing Total**	**600**	**4,532**	**137**	**-**	**-**	**-**	**4,669**
6	Customer Care - Supervision	700-10	1,504					1,504
7	Customer Contact - ABSU contract	700-20	47,961	4,891	27	135		53,014
8	Bad Debt Management and Administration	700-30	3,384	312	21			3,718
9	Customer Management & Sales	700-40	5,645	1,095				6,740
10	**Customer Care Total**	**700**	**58,494**	**6,298**	**48**	**135**	**-**	**64,975**
11	Business & IT Services - Supervision	800-10	999		0			999
12	Application Management	800-20	10,942	387				11,329
13	Infrastructure Management	800-30	6,026					6,026
14	Procurement Services	800-40	821					821
15	**Business & IT Services Total**	**800**	**18,788**	**387**	**0**	**-**	**-**	**19,176**
16	Administration & General	900-11	5,608	232	110			5,950
17	Insurance	900-12	4,410	861				5,271
18	Finance and Regulatory Affairs	900-13	9,110	381				9,491
19	Shared Services Agreement	900-14	742	8,326	251	321		9,640
20	Corporate Administration Total	900-10	19,870	9,801	361	321	-	30,353
21	Forecasting	900-20	1,721					1,721
22	Public Affairs	900-30	1,616	234				1,850
23	Business Development	900-40	2,013					2,013
24	Human Resources	900-50	6,551					6,551
25	Other Post Employment Benefits (OPEB)	900-60	5,320	937				6,257
26	**Administration & General Total**	**900**	**37,091**	**10,972**	**361**	**321**	**-**	**48,745**
27	**Total Gross O&M Expenses**		**206,519**	**29,852**	**773**	**794**	**-**	**237,938**
28	Less: O&M Difference from Allowed			1,379				1,379
29	Less: Vehicle Lease Reclass							-
30	Less: Capitalized Overhead		(28,905)	(4,372)	(119)	(114)		(33,510)
31	**Total O&M Expenses**		**$ 177,614**	**$ 26,859**	**$ 654**	**$ 680**	**$ -**	**$ 205,806**

FORTISBC ENERGY INC (COMBINED)
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	2006	2007	2008	2009	2010	Projection 2011	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	M&E Costs	$ 40,312	$ 44,601	$ 42,244	$ 44,495	$ 47,051	$ 52,316	$ 58,567	$ 60,697
2	COPE Costs	22,591	22,074	23,134	25,677	28,717	31,237	36,133	38,131
3	COPE Customer Services Costs							11,824	11,177
4	IBEW Costs	24,428	24,593	25,761	26,631	27,748	30,839	33,159	34,931
5									
6	**Labour Costs**	**87,331**	**91,268**	**91,138**	**96,803**	**103,516**	**114,391**	**139,683**	**144,935**
7									
8	Vehicle Costs	4,871	5,362	5,626	5,516	4,312	4,045	4,484	4,544
9	Employee Expenses	3,836	3,961	4,854	4,777	6,375	4,688	6,172	6,351
10	Materials and Supplies	5,021	5,556	6,844	7,123	7,878	6,593	8,117	8,490
11	Office Furnishing & Equipment	47	-	-	-	19			
12	Computer Costs	8,944	8,021	7,890	8,417	10,773	11,124	14,734	15,306
13	Fees and Administration Costs	42,476	33,862	36,689	34,359	41,131	40,383	74,264	79,629
14	Contractor Costs	57,763	59,169	62,484	64,806	68,661	69,807	23,920	26,386
15	Facilities	12,517	13,405	13,161	14,227	15,164	15,544	18,511	16,344
16	Recoveries & Revenue	(16,435)	(15,489)	(15,520)	(15,994)	(19,892)	(18,244)	(28,758)	(28,220)
17									
18	**Non-Labour Costs**	**119,040**	**113,846**	**122,029**	**123,231**	**134,422**	**133,942**	**121,444**	**128,831**
19									
20	**Total Gross O&M Expenses**	**206,371**	**205,115**	**213,167**	**220,034**	**237,938**	**248,333**	**261,127**	**273,766**
21									
22	Add: Shared Corporate Services								
23	Add: PST Savings						730		
24	Less: O&M Difference from Allowed	-	-	-	-	1,379			
25	Less: Vehicle Lease Reclass	(2,100)	(2,008)	(1,988)	(1,804)	-			
26	Less: Capitalized Overhead	(32,034)	(32,470)	(32,718)	(33,365)	(33,510)	(34,857)	(36,558)	(38,327)
27									
28	**Total O&M Expenses**	**$ 172,237**	**$ 170,637**	**$ 178,461**	**$ 184,865**	**$ 205,806**	**$ 214,206**	**$ 224,569**	**$ 235,438**

FORTISBC ENERGY INC (COMBINED)
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
($000)

Line No.	Particulars	Reference	2006	2007	2008	2009	2010	Projection 2011	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Distribution Supervision	100-11	$ 9,695	$ 10,769	$ 10,970	$ 11,688	$ 11,846	$ 11,259	$ 13,305	$ 13,825
2	Distribution Supervision Total	100-10	9,695	10,769	10,970	11,688	11,846	11,259	13,305	13,825
3	Operation Centre - Distribution	100-21	6,445	6,187	6,514	6,556	11,099	11,323	12,743	13,443
4	Asset Management - Distribution	100-22	1,415	970	1,052	1,355	1,762	2,302	3,259	4,587
5	Preventative Maintenance - Distribution	100-23	1,774	1,810	2,486	3,146	2,324	2,555	3,202	3,483
6	Distribution Operations - General	100-24	5,369	5,580	5,944	5,432	6,790	6,926	7,003	7,355
7	Emergency Management	100-25	6,974	6,701	7,855	7,277	5,445	6,380	5,938	6,134
8	Distribution Operations Total	100-20	21,978	21,248	23,851	23,766	27,421	29,486	32,145	35,002
9	Distribution Corrective - Meters	100-31	1,096	1,356	1,431	1,554	2,102	1,822	1,886	1,945
10	Distribution Corrective - Propane	100-32	46	36	37	21	2	5	-	-
11	Distribution Corrective - Leak Repair	100-33	942	1,180	1,136	1,195	1,445	1,276	1,374	1,415
12	Distribution Corrective - Stations	100-34	450	598	768	647	643	678	773	793
13	Distribution Corrective - General	100-35	473	445	396	310	466	430	638	987
14	Distribution Maintenance Total	100-30	3,008	3,616	3,767	3,727	4,659	4,210	4,671	5,140
15	**Distribution Total**	**100**	**34,681**	**35,633**	**38,588**	**39,181**	**43,925**	**44,955**	**50,121**	**53,966**
16	Transmission Supervision	200-11	1,889	2,194	1,841	2,924	3,205	4,502	5,497	6,453
17	Transmission Supervision Total	200-10	1,889	2,194	1,841	2,924	3,205	4,502	5,497	6,453
18	Pipeline Operation	200-21	1,789	2,860	3,578	4,549	3,451	1,650	3,622	3,766
19	Right of Way	200-22	1,939	1,386	1,514	1,566	1,706	536	730	808
20	Compression	200-23	2,329	2,389	2,228	2,451	2,900	915	2,171	2,239
21	Gas Control	200-24	1,939	1,848	1,905	2,471	2,611	3,132	2,848	3,000
22	Transmission Pipeline Integrity Project (TPIP)	200-25	4,065	3,284	4,202	4,285	2,722	3,240	2,611	2,797
23	Transmission Operations Total	200-20	12,062	11,767	13,427	15,322	13,391	9,473	11,983	12,610
24	Pipeline - Maintenance	200-31	639	252	483	499	710	3,594	2,830	2,684
25	Compression - Maintenance	200-32	1,296	972	1,712	1,073	958	2,714	1,624	1,764
26	TPIP - Maintenance	200-33	435	877	338	899	869	954	1,567	1,587
27	Transmission Maintenance Total	200-30	2,370	2,101	2,533	2,471	2,537	7,263	6,021	6,035
28	**Transmission Total**	**200**	**16,322**	**16,062**	**17,801**	**20,717**	**19,132**	**21,238**	**23,502**	**25,098**
29	LNG Plant Operations	300-11	524	781	720	845	1,368	2,126	2,780	2,937
30	LNG Plant Operations Total	300-10	524	781	720	845	1,368	2,126	2,780	2,937
31	LNG Plant Maintenance	300-21	291	198	254	255	431	760	797	824
32	LNG Plant Maintenance Total	300-20	291	198	254	255	431	760	797	824
33	**LNG Plant Total**	**300**	**815**	**980**	**974**	**1,100**	**1,799**	**2,886**	**3,577**	**3,761**
34	Measurement Operations	400-11	3,633	3,955	3,788	4,142	4,594	4,252	4,951	5,261
35	Measurement Operations Total	400-10	3,633	3,955	3,788	4,142	4,594	4,252	4,951	5,261
36	Measurement Maintenance	400-21	3,404	2,326	2,288	2,396	2,197	3,367	2,539	2,601
37	Measurement Maintenance Total	400-20	3,404	2,326	2,288	2,396	2,197	3,367	2,539	2,601
38	**Measurement Total**	**400**	**7,037**	**6,281**	**6,075**	**6,538**	**6,791**	**7,619**	**7,491**	**7,861**
39	Facilities Management	500-10	6,516	6,266	6,813	7,545	7,966	7,504	10,433	9,451
40	Shops & Stores	500-20	2,807	3,233	3,405	3,747	4,016	3,907	4,677	4,783
41	Operations Engineering	500-30	5,791	6,143	6,288	6,930	9,067	9,297	10,621	11,092
42	Property Services	500-40	881	760	1,011	991	1,204	1,283	1,411	1,453
43	System Integrity	500-50	1,981	2,141	2,243	2,415	2,449	2,774	2,567	2,608
44	Environmental Health & Safety	500-60	1,162	1,066	1,191	1,457	2,365	2,404	2,893	3,057
45	Operations Governance	500-70	1,159	1,351	1,464	1,445	1,660	1,899	1,649	1,705
46	**General Operations Total**	**500**	**20,298**	**20,960**	**22,416**	**24,530**	**28,727**	**29,068**	**34,251**	**34,149**

FORTISBC ENERGY INC (COMBINED)
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
($000)

Line No.	Particulars	Reference	2006	2007	2008	2009	2010	Projection 2011	Forecast 2012	Forecast 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Energy Efficiency	600-10	$ 1,556	$ 1,599	$ 1,740	$ 1,624	$ (7)	$ (0)	$ 0	$ (0)
2	Marketing - Supervision	600-20	562	1,174	553	1,326	780	(825)	(807)	(785)
3	Corporate & Marketing Communications	600-30	3,540	2,533	3,147	3,126	3,270	2,975	3,887	4,103
4	Marketing Planning & Development	600-40	686	607	568	565	626	531	955	981
5	**Marketing Total**	**600**	**6,344**	**5,913**	**6,009**	**6,641**	**4,669**	**2,682**	**4,035**	**4,298**
6	Customer Care - Supervision	700-10	735	724	878	1,474	1,504	2,205	2,793	2,883
7	Customer Contact	700-20	49,190	49,982	51,128	51,325	53,014	54,601	45,431	48,917
8	Bad Debt Management and Administration	700-30	10,853	4,927	5,446	6,255	3,718	5,871	5,445	5,494
9	Customer Management & Sales	700-40	3,274	3,456	4,195	4,278	6,740	7,049	8,189	8,545
10	**Customer Care Total**	**700**	**64,052**	**59,088**	**61,647**	**63,332**	**64,975**	**69,726**	**61,859**	**65,839**
11	Business & IT Services - Supervision	800-10	1,858	1,857	1,011	1,568	999	1,194	0	-
12	Application Management	800-20	6,676	8,172	8,313	9,610	11,329	12,888	16,540	17,297
13	Infrastructure Management	800-30	5,472	5,675	5,270	5,494	6,026	7,108	8,760	9,154
14	Procurement Services	800-40	674	681	670	700	821	864	1,265	1,412
15	**Business & IT Services Total**	**800**	**14,681**	**16,386**	**15,264**	**17,372**	**19,176**	**22,053**	**26,564**	**27,863**
16	Administration & General	900-11	3,352	3,025	4,375	723	5,950	3,691	2,566	3,450
17	Insurance	900-12	5,734	5,797	5,380	5,444	5,271	5,561	5,437	5,257
18	Finance and Regulatory Affairs	900-13	7,519	8,189	8,972	9,882	9,491	10,335	11,564	11,892
19	Shared Services Agreement	900-14	8,780	9,168	8,768	9,009	9,640	9,103	11,277	11,234
20	Corporate Administration Total	900-10	25,385	26,180	27,496	25,058	30,353	28,690	30,844	31,833
21	Forecasting	900-20	1,184	1,025	934	968	1,721	1,696	3,036	3,335
22	Public Affairs	900-30	1,468	1,537	1,567	1,883	1,850	2,030	2,253	2,309
23	Business Development	900-40	1,194	982	1,017	1,253	2,013	3,808	3,979	4,113
24	Human Resources	900-50	4,041	4,724	4,540	5,519	6,551	6,947	8,152	8,457
25	Other Post Employment Benefits (OPEB)	900-60	8,870	9,364	8,841	5,942	6,257	4,935	1,464	883
26	**Administration & General Total**	**900**	**42,141**	**43,812**	**44,394**	**40,623**	**48,745**	**48,107**	**49,727**	**50,930**
27	**Total Gross O&M Expenses**		**206,371**	**205,115**	**213,167**	**220,034**	**237,938**	**248,333**	**261,127**	**273,766**
28	Add: Shared Corporate Services									
29	Add: PST Savings							730		
30	Less: O&M Difference from Allowed						1,379			
31	Less: Vehicle Lease Reclass		(2,100)	(2,008)	(1,988)	(1,804)	-			
32	Less: Capitalized Overhead		(32,034)	(32,470)	(32,718)	(33,365)	(33,510)	(34,857)	(36,558)	(38,327)
33	**Total O&M Expenses**		**$ 172,237**	**$ 170,637**	**$ 178,461**	**$ 184,865**	**$ 205,806**	**$ 214,206**	**$ 224,569**	**$ 235,438**

Appendix D-3

HISTORIC AND FORECAST O&M BY BUSINESS AREA

HISTORICAL AND FORECAST O&M EXPENSES BY CUSTOMER
($000)

	Actual					Projection	Forecast	Forecast
	2006	2007	2008	2009	2010	2011	2012	2013
FEU Total Gross Nominal O&M Expenses	$ 206,371	$ 205,115	$ 213,167	$ 220,034	$ 237,938	$ 249,063	$ 261,127	$ 273,765
FEU Total Gross Real O&M Expenses	$ 226,388	$ 221,523	$ 225,957	$ 228,396	$ 242,220	$ 249,063	$ 256,031	$ 263,075
FEU Average Number of Customers	893	910	923	934	943	953	962	971
FEU Nominal O&M per Customer	**$ 231**	**$ 225**	**$ 231**	**$ 236**	**$ 252**	**$ 261**	**$ 272**	**$ 282**
FEU Real O&M per Customer	**$ 254**	**$ 243**	**$ 245**	**$ 245**	**$ 257**	**$ 261**	**$ 266**	**$ 271**
FEI Total Gross Nominal O&M Expenses	$ 179,206	$ 178,973	$ 185,739	$ 191,945	$ 206,519	$ 214,680	$ 224,119	$ 236,471
FEI Total Gross Real O&M Expenses	$ 196,589	$ 193,290	$ 196,883	$ 199,239	$ 210,237	$ 214,680	$ 219,745	$ 227,238
FEI Average Number of Customers	803	816	826	833	839	847	853	860
FEI Nominal O&M per Customer	**$ 223**	**$ 219**	**$ 225**	**$ 230**	**$ 246**	**$ 254**	**$ 263**	**$ 275**
FEI Real O&M per Customer	**$ 245**	**$ 237**	**$ 238**	**$ 239**	**$ 251**	**$ 254**	**$ 258**	**$ 264**
FEVI Total Gross Nominal O&M Expenses	$ 25,524	$ 24,514	$ 25,782	$ 26,514	$ 29,852	$ 32,702	$ 35,236	$ 35,482
FEVI Total Gross Real O&M Expenses	$ 28,000	$ 26,475	$ 27,329	$ 27,521	$ 30,389	$ 32,702	$ 34,549	$ 34,097
FEVI Average Number of Customers	85	89	93	96	99	101	104	106
FEVI Nominal O&M per Customer	**$ 299**	**$ 275**	**$ 277**	**$ 276**	**$ 302**	**$ 323**	**$ 340**	**$ 334**
FEVI Real O&M per Customer	**$ 328**	**$ 296**	**$ 294**	**$ 286**	**$ 307**	**$ 323**	**$ 333**	**$ 321**
FEW Total Gross Nominal O&M Expenses	$ 821	$ 793	$ 906	$ 791	$ 773	$ 868	$ 906	$ 915
FEW Total Gross Real O&M Expenses	$ 901	$ 856	$ 960	$ 821	$ 787	$ 868	$ 889	$ 879
FEW Average Number of Customers	2	2	2	3	3	3	3	3
FEW Nominal O&M per Customer	**$ 347**	**$ 332**	**$ 372**	**$ 314**	**$ 299**	**$ 335**	**$ 347**	**$ 348**
FEW Real O&M per Customer	**$ 380**	**$ 358**	**$ 395**	**$ 326**	**$ 304**	**$ 335**	**$ 341**	**$ 335**
Fort Nelson Total Gross Nominal O&M Expenses	$ 820	$ 835	$ 740	$ 784	$ 794	$ 812	$ 865	$ 897
Fort Nelson Total Gross Real O&M Expenses	$ 899	$ 902	$ 784	$ 814	$ 808	$ 812	$ 849	$ 862
Fort Nelson Average Number of Customers	2	2	2	2	2	2	2	2
Fort Nelson Nominal O&M per Customer	**$ 353**	**$ 357**	**$ 314**	**$ 333**	**$ 336**	**$ 340**	**$ 360**	**$ 369**
Fort Nelson Real O&M per Customer	**$ 387**	**$ 385**	**$ 333**	**$ 346**	**$ 342**	**$ 340**	**$ 353**	**$ 355**

HISTORICAL AND FORECAST GROSS REAL O&M EXPENSES BY BUSINESS AREA
($000)

Business Area	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Projection 2011	Forecast 2012	Forecast 2013
FortisBC Energy Inc (Combined)								
Distribution	41,977	42,106	45,088	44,556	48,707	49,330	53,141	55,934
Transmission	16,047	16,075	17,762	20,010	18,745	21,128	22,586	23,603
Energy Supply & Resource Development	3,053	2,737	2,646	2,862	3,309	3,848	3,965	4,128
Customer Service	61,346	60,040	60,735	60,536	59,631	62,686	59,604	62,185
Energy Solution & External Relations	12,673	12,102	13,026	14,034	15,890	15,834	18,708	19,346
Information Technology	13,964	15,036	14,363	15,712	17,713	20,516	21,499	21,810
Operations Engineering	10,252	10,548	10,773	11,268	13,578	13,967	14,465	14,713
Operations Support	8,681	8,609	8,492	9,045	9,889	9,847	11,019	11,342
Facilities	7,153	6,910	7,265	7,905	8,287	7,819	7,739	6,623
Human Resources	5,632	6,377	6,318	6,723	8,486	8,280	8,791	9,016
Environmental & Safety	1,463	1,319	1,434	1,718	2,629	2,615	2,837	2,938
Finance and Regulatory	8,070	8,715	9,574	10,021	9,899	10,336	11,338	11,427
Corporate	36,077	30,949	28,481	24,005	25,457	22,856	20,339	20,010
Combined Total Gross O&M Expenses	**$ 226,388**	**$ 221,523**	**$ 225,957**	**$ 228,396**	**$ 242,220**	**$ 249,063**	**$ 256,031**	**$ 263,075**
FEI								
Distribution	34,787	35,996	39,013	38,915	42,641	43,153	46,708	49,064
Transmission	12,015	12,079	12,923	15,040	14,121	14,994	15,963	16,815
Energy Supply & Resource Development	3,053	2,737	2,650	2,862	3,309	3,748	3,866	4,032
Customer Service	55,308	54,628	55,221	55,189	54,251	56,935	54,307	56,657
Energy Solution & External Relations	11,552	10,875	11,691	12,886	14,537	14,370	17,083	17,719
Information Technology	13,423	14,512	13,884	15,276	17,319	20,095	21,086	21,401
Operations Engineering	9,570	9,993	10,130	10,659	12,577	13,288	13,801	14,062
Operations Support	8,557	8,600	8,492	9,045	9,889	9,847	11,019	11,342
Facilities	5,695	5,397	5,758	6,327	6,801	6,201	6,304	6,105
Human Resources	5,632	6,377	6,318	6,723	8,486	8,280	8,791	9,016
Environmental & Safety	1,463	1,319	1,434	1,718	2,629	2,615	2,837	2,938
Finance and Regulatory	7,779	8,431	9,251	9,697	9,511	9,953	10,855	10,954
Corporate	27,756	22,346	20,118	14,903	14,165	11,201	7,124	7,134
FEI Total Gross O&M Expenses	**$ 196,589**	**$ 193,290**	**$ 196,883**	**$ 199,239**	**$ 210,237**	**$ 214,680**	**$ 219,745**	**$ 227,238**
FEVI								
Distribution	6,250	5,206	5,113	4,767	5,332	5,379	5,674	6,120
Transmission	4,032	3,996	4,839	4,969	4,624	6,134	6,624	6,788
Energy Supply & Resource Development	-	-	(4)	-	-	100	98	96
Customer Service	5,855	5,222	5,294	5,181	5,115	5,459	5,155	5,381
Energy Solution & External Relations	1,121	1,227	1,336	1,149	1,353	1,464	1,624	1,628
Information Technology	540	523	479	436	394	421	414	409
Operations Engineering	683	555	643	609	1,001	679	664	651
Operations Support	124	9	(0)	(0)	-	-	-	-
Facilities	1,458	1,513	1,507	1,578	1,486	1,618	1,434	518
Human Resources	-	-	-	-	-	-	-	-
Environmental & Safety	-	-	-	-	-	-	-	-
Finance and Regulatory	291	284	323	324	388	383	483	473
Corporate	7,645	7,939	7,800	8,507	10,695	11,065	12,379	12,033
FEVI Total Gross O&M Expenses	**$ 28,000**	**$ 26,475**	**$ 27,329**	**$ 27,521**	**$ 30,389**	**$ 32,702**	**$ 34,549**	**$ 34,097**
FEW								
Distribution	610	553	626	519	390	451	422	413
Customer Service	40	50	80	30	127	156	143	148
Corporate	250	253	254	272	269	261	324	318
FEW Total Gross O&M Expenses	**$ 901**	**$ 856**	**$ 960**	**$ 821**	**$ 787**	**$ 868**	**$ 889**	**$ 879**
Fort Nelson								
Distribution	331	352	336	354	344	347	337	336
Customer Service	143	140	140	137	137	136	-	-
Corporate	425	410	308	323	327	329	512	525
Fort Nelson Total Gross O&M Expenses	**$ 899**	**$ 902**	**$ 784**	**$ 814**	**$ 808**	**$ 812**	**$ 849**	**$ 862**

HISTORICAL AND FORECAST GROSS NOMINAL O&M EXPENSES BY BUSINESS AREA
($000)

	Actual					Projection	Forecast	Forecast
Business Area	2006	2007	2008	2009	2010	2011	2012	2013
FEU								
Distribution	38,266	38,987	42,536	42,925	47,846	49,330	54,198	58,207
Transmission	14,628	14,885	16,757	19,277	18,413	21,128	23,036	24,562
Energy Supply & Resource Development	2,783	2,534	2,496	2,757	3,251	3,848	4,043	4,296
Customer Service	55,921	55,593	57,297	58,320	58,577	62,686	60,791	64,712
Energy Solution & External Relations	11,552	11,206	12,289	13,521	15,609	15,834	19,080	20,132
Information Technology	12,729	13,922	13,550	15,137	17,400	20,516	21,927	22,696
Operations Engineering	9,346	9,767	10,163	10,855	13,338	13,967	14,753	15,310
Operations Support	7,913	7,971	8,011	8,714	9,715	9,847	11,238	11,802
Facilities	6,521	6,398	6,853	7,616	8,140	7,819	7,893	6,892
Human Resources	5,134	5,904	5,960	6,477	8,335	8,280	8,966	9,382
Environmental & Safety	1,333	1,222	1,353	1,655	2,583	2,615	2,893	3,057
Finance and Regulatory	7,357	8,069	9,032	9,654	9,724	10,336	11,564	11,892
Corporate	32,887	28,656	26,869	23,126	25,007	22,856	20,743	20,824
FEU Total Gross Nominal O&M Expenses	**$ 206,370**	**$205,114**	**$ 213,167**	**$ 220,034**	**$ 237,938**	**$ 249,063**	**$ 261,127**	**$ 273,765**
FEI								
Distribution	31,711	33,330	36,805	37,491	41,887	43,153	47,638	51,058
Transmission	10,953	11,184	12,191	14,490	13,871	14,994	16,280	17,499
Energy Supply & Resource Development	2,783	2,534	2,500	2,757	3,251	3,748	3,943	4,196
Customer Service	50,417	50,582	52,095	53,168	53,292	56,935	55,388	58,959
Energy Solution & External Relations	10,531	10,069	11,029	12,414	14,280	14,370	17,423	18,439
Information Technology	12,236	13,437	13,099	14,717	17,012	20,095	21,505	22,270
Operations Engineering	8,724	9,253	9,556	10,268	12,355	13,288	14,076	14,633
Operations Support	7,800	7,963	8,012	8,714	9,715	9,847	11,238	11,802
Facilities	5,192	4,997	5,432	6,095	6,681	6,201	6,430	6,353
Human Resources	5,134	5,904	5,960	6,477	8,335	8,280	8,966	9,382
Environmental & Safety	1,333	1,222	1,353	1,655	2,583	2,615	2,893	3,057
Finance and Regulatory	7,091	7,806	8,727	9,342	9,343	9,953	11,071	11,399
Corporate	25,302	20,691	18,980	14,357	13,915	11,201	7,266	7,424
FEI Total Gross Nominal O&M Expenses	**$ 179,206**	**$178,973**	**$ 185,739**	**191,945**	**$ 206,519**	**$ 214,680**	**$ 224,119**	**$ 236,471**
FEVI								
Distribution	5,697	4,820	4,823	4,593	5,238	5,379	5,787	6,369
Transmission	3,676	3,700	4,566	4,787	4,542	6,134	6,755	7,064
Energy Supply & Resource Development	-	-	(4)	-	-	100	100	100
Customer Service	5,338	4,835	4,994	4,991	5,025	5,459	5,257	5,599
Energy Solution & External Relations	1,022	1,136	1,260	1,107	1,329	1,464	1,657	1,694
Information Technology	493	484	452	420	387	421	422	426
Operations Engineering	622	514	607	587	983	679	677	677
Operations Support	113	8	(0)	(0)	-	-	-	-
Facilities	1,329	1,401	1,421	1,521	1,460	1,618	1,463	539
Human Resources	-	-	-	-	-	-	-	-
Environmental & Safety	-	-	-	-	-	-	-	-
Finance and Regulatory	266	263	304	312	381	383	493	493
Corporate	6,969	7,351	7,359	8,196	10,506	11,065	12,625	12,522
FEVI Total Gross Nominal O&M Expenses	**$ 25,524**	**$ 24,514**	**$ 25,782**	**$ 26,514**	**$ 29,852**	**$ 32,702**	**$ 35,236**	**$ 35,482**
FEW								
Distribution	556	512	590	500	383	451	430	430
Customer Service	36	47	76	29	125	156	146	154
Corporate	228	234	240	262	264	261	330	331
FEW Total Gross Nominal O&M Expenses	**$ 821**	**$ 793**	**$ 906**	**$ 791**	**$ 773**	**$ 868**	**$ 906**	**$ 915**
Fort Nelson								
Distribution	302	326	317	341	338	347	344	350
Customer Service	130	130	132	132	135	136	-	-
Corporate	388	380	290	311	321	329	522	547
Fort Nelson Total Gross Nominal O&M Expenses	**$ 820**	**$ 835**	**$ 740**	**$ 784**	**$ 794**	**$ 812**	**$ 865**	**$ 897**

Appendix D-4

HISTORIC FTE

FortisBC Energy Inc.
Combined - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	37	36	36	38	40	45	46	47
2	Facilities	12	13	10	10	13	17	18	18
3	Operations Engineering	113	119	134	143	153	178	193	193
4	Operations Support	131	129	129	124	125	133	139	142
5	Customer Service	31	23	22	25	32	367	325	309
6	Human Resources	77	75	78	93	96	70	71	72
7	Environmental & Safety	8	8	8	10	11	14	14	14
8	Information Technology	46	49	51	55	64	66	75	76
9	Distribution	543	547	565	559	579	658	660	669
10	Energy Solution & External Relations	65	66	64	74	96	118	125	125
11	Finance and Regulatory	61	60	65	67	65	68	69	69
12	Transmission	60	63	61	67	72	86	92	94
13	Corporate	2	2	2	2	2	1	1	1
14									
15	Total FTE	1,187	1,191	1,227	1,267	1,347	1,821	1,828	1,829
16									
17	Affiliation Summary								
18	COPE	416	421	431	441	464	759	754	749
19	IBEW	499	495	503	494	506	570	564	568
20	M&E	272	275	293	332	377	492	510	512
21	Total FTE	1,187	1,191	1,227	1,267	1,347	1,821	1,828	1,829

FortisBC Energy Inc.
Combined - Historic and Forecast FTE by Business Unit and Affiliation

Line no.	Business Unit & Affiliation	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development								
2	COPE	13	13	13	13	14	16	16	16
3	IBEW	-	-	-	-	-	-	-	-
4	M&E	24	22	23	25	26	29	30	31
5		37	36	36	38	40	45	46	47
6	Facilities								
7	COPE	6	6	5	5	8	9	10	10
8	IBEW	4	4	3	3	3	6	6	6
9	M&E	2	3	2	2	2	2	2	2
10		12	13	10	10	13	17	18	18
11	Operations Engineering								
12	COPE	80	88	94	99	108	124	134	134
13	IBEW	1	1	1	1	0	1	1	1
14	M&E	32	30	38	44	45	53	58	58
15		113	119	134	143	153	178	193	193
16	Operations Support								
17	COPE	44	42	41	39	40	45	47	48
18	IBEW	82	81	81	78	77	80	84	86
19	M&E	6	7	7	7	8	8	8	8
20		131	129	129	124	125	133	139	142
21	Customer Service								
22	COPE	12	16	16	15	20	287	248	236
23	IBEW	7	-	-	-	-	-	-	-
24	M&E	12	7	7	10	13	80	77	73
25		31	23	22	25	32	367	325	309
26	Human Resources								
27	COPE	36	34	35	43	41	12	12	12
28	IBEW	6	7	7	7	4	3	3	3
29	M&E	34	34	36	43	51	55	56	57
30		77	75	78	93	96	70	71	72
31	Environmental & Safety								
32	COPE	1	1	-	1	1	-	-	-
33	IBEW	-	-	-	-	-	-	-	-
34	M&E	6	7	8	9	10	14	14	14
35		8	8	8	10	11	14	14	14
36	Information Technology								
37	COPE	21	21	21	20	22	24	32	33
38	IBEW	-	-	-	-	-	-	-	-
39	M&E	25	28	30	35	42	42	43	43
40		46	49	51	55	64	66	75	76
41	Distribution								
42	COPE	137	137	142	140	146	175	188	193
43	IBEW	351	354	368	361	373	421	408	408
44	M&E	55	56	55	58	60	62	65	69
45		543	547	565	559	579	657	660	669
46	Energy Solution & External Relations								
47	COPE	16	17	16	16	18	20	20	20
48	IBEW	5	4	1	-	-	-	-	-
49	M&E	44	46	48	58	78	98	105	105
50		65	66	64	74	96	118	125	125
51	Finance and Regulatory								
52	COPE	40	37	40	38	35	36	36	36
53	IBEW	-	-	-	-	-	-	-	-
54	M&E	21	23	26	29	30	32	33	33
55		61	60	65	67	65	68	69	69
56	Transmission								
57	COPE	9	10	9	11	11	12	13	13
58	IBEW	42	44	43	45	49	59	62	64
59	M&E	9	9	9	11	12	15	17	17
60		60	63	61	67	72	86	92	94
61	Corporate								
62	COPE	-	-	-	-	-	-	-	-
63	IBEW	-	-	-	-	-	-	-	-
64	M&E	2	2	2	2	2	1	1	1
65		2	2	2	2	2	1	1	1
66									
67	Total FTE	1,187	1,191	1,227	1,267	1,347	1,821	1,828	1,829

FortisBC Energy Inc.
Mainland - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	37	36	36	38	40	45	46	47
2	Facilities	12	13	10	10	13	17	18	18
3	Operations Engineering	111	117	132	142	152	176	191	191
4	Operations Support	131	129	129	124	125	133	139	142
5	Customer Service	19	23	22	25	32	367	325	309
6	Human Resources	77	75	78	93	96	70	71	72
7	Environmental & Safety	8	8	8	10	11	14	14	14
8	Information Technology	44	47	49	54	63	65	74	75
9	Distribution	457	471	490	484	502	571	577	586
10	Energy Solution & External Relations	56	56	58	68	90	110	117	117
11	Finance and Regulatory	61	60	65	67	65	68	69	69
12	Transmission	44	46	44	49	51	55	59	60
13	Corporate	2	2	2	2	2	1	1	1
14									
15	Total FTE	1,059	1,084	1,124	1,165	1,241	1,692	1,701	1,701
16									
17	Affiliation Summary								
18	COPE	416	421	431	441	464	759	755	750
19	IBEW	397	409	421	412	420	465	460	463
20	M&E	247	255	273	312	357	468	486	488
21	Total FTE	1,059	1,084	1,124	1,165	1,241	1,692	1,701	1,701

FortisBC Energy Inc.
Mainland - Historic and Forecast FTE by Business Unit and Affiliation

Line no.	Business Unit & Affiliation	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development								
2	COPE	13	13	13	13	14	16	16	16
3	IBEW	-	-	-	-	-	-	-	-
4	M&E	24	22	23	25	26	29	30	31
5		37	36	36	38	40	45	46	47
6	Facilities								
7	COPE	6	6	5	5	8	9	10	10
8	IBEW	4	4	3	3	3	6	6	6
9	M&E	2	3	2	2	2	2	2	2
10		12	13	10	10	13	17	18	18
11	Operations Engineering								
12	COPE	80	88	94	99	108	124	134	134
13	IBEW	-	-	-	-	-	-	-	-
14	M&E	30	29	38	43	44	53	58	58
15		111	117	132	142	152	176	191	191
16	Operations Support								
17	COPE	44	42	41	39	40	45	47	48
18	IBEW	82	81	81	78	77	80	84	86
19	M&E	6	7	7	7	8	8	8	8
20		131	129	129	124	125	133	139	142
21	Customer Service								
22	COPE	12	16	16	15	20	287	248	236
23	IBEW	-	-	-	-	-	-	-	-
24	M&E	8	7	7	10	13	80	77	73
25		19	23	22	25	32	367	325	309
26	Human Resources								
27	COPE	36	34	35	43	41	12	12	12
28	IBEW	6	7	7	7	4	3	3	3
29	M&E	34	34	36	43	51	55	56	57
30		77	75	78	93	96	70	71	72
31	Environmental & Safety								
32	COPE	1	1	-	1	1	-	-	-
33	IBEW	-	-	-	-	-	-	-	-
34	M&E	6	7	8	9	10	14	14	14
35		8	8	8	10	11	14	14	14
36	Information Technology								
37	COPE	21	21	21	20	22	24	32	33
38	IBEW	-	-	-	-	-	-	-	-
39	M&E	23	26	28	34	41	41	42	42
40		44	47	49	54	63	65	74	75
41	Distribution								
42	COPE	137	137	142	140	146	175	188	193
43	IBEW	272	283	299	292	302	340	330	330
44	M&E	48	51	49	52	55	56	59	63
45		457	471	490	484	502	571	577	586
46	Energy Solution & External Relations								
47	COPE	16	17	16	16	18	20	20	20
48	IBEW	1	-	-	-	-	-	-	-
49	M&E	39	40	42	52	72	90	97	97
50		56	56	58	68	90	110	117	117
51	Finance and Regulatory								
52	COPE	40	37	40	38	35	36	36	36
53	IBEW	-	-	-	-	-	-	-	-
54	M&E	21	23	26	29	30	32	33	33
55		61	60	65	67	65	68	69	69
56	Transmission								
57	COPE	9	10	9	11	11	12	13	13
58	IBEW	32	33	32	34	35	36	37	38
59	M&E	3	3	3	4	5	7	9	9
60		44	46	44	49	51	55	59	60
61	Corporate								
62	COPE	-	-	-	-	-	-	-	-
63	IBEW	-	-	-	-	-	-	-	-
64	M&E	2	2	2	2	2	1	1	1
65		2	2	2	2	2	1	1	1
66									
67	Total FTE	1,059	1,084	1,124	1,165	1,241	1,692	1,701	1,701

FortisBC Energy Inc.
Vancouver Island - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	-	-	-	-	-	-	-	-
2	Facilities	-	-	-	-	-	-	-	-
3	Operations Engineering	3	2	2	2	1	2	2	2
4	Operations Support	-	-	-	-	-	-	-	-
5	Customer Service	11	-	-	-	-	-	-	-
6	Human Resources	-	-	-	-	-	-	-	-
7	Environmental & Safety	-	-	-	-	-	-	-	-
8	Information Technology	2	2	2	1	1	1	1	1
9	Distribution	81	71	70	70	72	82	79	79
10	Energy Solution & External Relations	9	10	7	6	6	8	8	8
11	Finance and Regulatory	-	-	-	-	-	-	-	-
12	Transmission	17	17	17	18	21	31	33	34
13	Corporate	-	-	-	-	-	-	-	-
14									
15	Total FTE	122	102	97	97	101	124	123	124
16									
17	Affiliation Summary								
18	COPE	-	-	-	-	-	-	-	-
19	IBEW	98	82	78	77	82	101	100	101
20	M&E	24	19	19	20	19	23	23	23
21	Total FTE	122	102	97	97	101	124	123	124

FortisBC Energy Inc.
Vancouver Island - Historic and Forecast FTE by Business Unit and Affiliation

Line no.	Business Unit & Affiliation	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development								
2	COPE	-	-	-	-	-	-	-	-
3	IBEW	-	-	-	-	-	-	-	-
4	M&E	-	-	-	-	-	-	-	-
5		-	-	-	-	-	-	-	-
6	Facilities								
7	COPE	-	-	-	-	-	-	-	-
8	IBEW	-	-	-	-	-	-	-	-
9	M&E	-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11	Operations Engineering								
12	COPE	-	-	-	-	-	-	-	-
13	IBEW	1	1	1	1	0	1	1	1
14	M&E	2	1	1	1	1	1	1	1
15		3	2	2	2	1	2	2	2
16	Operations Support								
17	COPE	-	-	-	-	-	-	-	-
18	IBEW	-	-	-	-	-	-	-	-
19	M&E	-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21	Customer Service								
22	COPE	-	-	-	-	-	-	-	-
23	IBEW	7	-	-	-	-	-	-	-
24	M&E	4	-	-	-	-	-	-	-
25		11	-	-	-	-	-	-	-
26	Human Resources								
27	COPE	-	-	-	-	-	-	-	-
28	IBEW	-	-	-	-	-	-	-	-
29	M&E	-	-	-	-	-	-	-	-
30		-	-	-	-	-	-	-	-
31	Environmental & Safety								
32	COPE	-	-	-	-	-	-	-	-
33	IBEW	-	-	-	-	-	-	-	-
34	M&E	-	-	-	-	-	-	-	-
35		-	-	-	-	-	-	-	-
36	Information Technology								
37	COPE	-	-	-	-	-	-	-	-
38	IBEW	-	-	-	-	-	-	-	-
39	M&E	2	2	2	1	1	1	1	1
40		2	2	2	1	1	1	1	1
41	Distribution								
42	COPE	-	-	-	-	-	-	-	-
43	IBEW	75	66	65	65	67	77	74	74
44	M&E	6	5	5	5	5	5	5	5
45		81	71	70	70	72	82	79	79
46	Energy Solution & External Relations								
47	COPE	-	-	-	-	-	-	-	-
48	IBEW	4	4	1	-	-	-	-	-
49	M&E	5	6	6	6	6	8	8	8
50		9	10	7	6	6	8	8	8
51	Finance and Regulatory								
52	COPE	-	-	-	-	-	-	-	-
53	IBEW	-	-	-	-	-	-	-	-
54	M&E	-	-	-	-	-	-	-	-
55		-	-	-	-	-	-	-	-
56	Transmission								
57	COPE	-	-	-	-	-	-	-	-
58	IBEW	11	11	11	11	14	23	25	26
59	M&E	6	6	6	7	7	8	8	8
60		17	17	17	18	21	31	33	34
61	Corporate								
62	COPE	-	-	-	-	-	-	-	-
63	IBEW	-	-	-	-	-	-	-	-
64	M&E	-	-	-	-	-	-	-	-
65		-	-	-	-	-	-	-	-
66									
67	Total FTE	122	102	97	97	101	124	123	124

FortisBC Energy Inc.
Whistler - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	-	-	-	-	-	-	-	-
2	Facilities	-	-	-	-	-	-	-	-
3	Operations Engineering	-	-	-	-	-	-	-	-
4	Operations Support	-	-	-	-	-	-	-	-
5	Customer Service	-	-	-	-	-	-	-	-
6	Human Resources	-	-	-	-	-	-	-	-
7	Environmental & Safety	-	-	-	-	-	-	-	-
8	Information Technology	-	-	-	-	-	-	-	-
9	Distribution	2	2	2	2	2	2	2	2
10	Energy Solution & External Relations	-	-	-	-	-	-	-	-
11	Finance and Regulatory	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-
13	Corporate	-	-	-	-	-	-	-	-
14									
15	Total FTE	2	2	2	2	2	2	2	2
16									
17	Affiliation Summary								
18	COPE	-	-	-	-	-	-	-	-
19	IBEW	2	2	2	2	2	2	2	2
20	M&E	-	-	-	-	-	-	-	-
21	Total FTE	2	2	2	2	2	2	2	2

FortisBC Energy Inc.
Whistler - Historic and Forecast FTE by Business Unit and Affiliation

Line no.	Business Unit & Affiliation	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development								
2	COPE	-	-	-	-	-	-	-	-
3	IBEW	-	-	-	-	-	-	-	-
4	M&E	-	-	-	-	-	-	-	-
5		-	-	-	-	-	-	-	-
6	Facilities								
7	COPE	-	-	-	-	-	-	-	-
8	IBEW	-	-	-	-	-	-	-	-
9	M&E	-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11	Operations Engineering								
12	COPE	-	-	-	-	-	-	-	-
13	IBEW	-	-	-	-	-	-	-	-
14	M&E	-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-
16	Operations Support								
17	COPE	-	-	-	-	-	-	-	-
18	IBEW	-	-	-	-	-	-	-	-
19	M&E	-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21	Customer Service								
22	COPE	-	-	-	-	-	-	-	-
23	IBEW	-	-	-	-	-	-	-	-
24	M&E	-	-	-	-	-	-	-	-
25		-	-	-	-	-	-	-	-
26	Human Resources								
27	COPE	-	-	-	-	-	-	-	-
28	IBEW	-	-	-	-	-	-	-	-
29	M&E	-	-	-	-	-	-	-	-
30		-	-	-	-	-	-	-	-
31	Environmental & Safety								
32	COPE	-	-	-	-	-	-	-	-
33	IBEW	-	-	-	-	-	-	-	-
34	M&E	-	-	-	-	-	-	-	-
35		-	-	-	-	-	-	-	-
36	Information Technology								
37	COPE	-	-	-	-	-	-	-	-
38	IBEW	-	-	-	-	-	-	-	-
39	M&E	-	-	-	-	-	-	-	-
40		-	-	-	-	-	-	-	-
41	Distribution								
42	COPE	-	-	-	-	-	-	-	-
43	IBEW	2	2	2	2	2	2	2	2
44	M&E	-	-	-	-	-	-	-	-
45		2	2	2	2	2	2	2	2
46	Energy Solution & External Relations								
47	COPE	-	-	-	-	-	-	-	-
48	IBEW	-	-	-	-	-	-	-	-
49	M&E	-	-	-	-	-	-	-	-
50		-	-	-	-	-	-	-	-
51	Finance and Regulatory								
52	COPE	-	-	-	-	-	-	-	-
53	IBEW	-	-	-	-	-	-	-	-
54	M&E	-	-	-	-	-	-	-	-
55		-	-	-	-	-	-	-	-
56	Transmission								
57	COPE	-	-	-	-	-	-	-	-
58	IBEW	-	-	-	-	-	-	-	-
59	M&E	-	-	-	-	-	-	-	-
60		-	-	-	-	-	-	-	-
61	Corporate								
62	COPE	-	-	-	-	-	-	-	-
63	IBEW	-	-	-	-	-	-	-	-
64	M&E	-	-	-	-	-	-	-	-
65		-	-	-	-	-	-	-	-
66									
67	Total FTE	2	2	2	2	2	2	2	2

FortisBC Energy Inc.
Fort Nelson - Historic and Forecast FTE by Business Unit

Line no.	Business Unit	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development	-	-	-	-	-	-	-	-
2	Facilities	-	-	-	-	-	-	-	-
3	Operations Engineering	-	-	-	-	-	-	-	-
4	Operations Support	-	-	-	-	-	-	-	-
5	Customer Service	-	-	-	-	-	-	-	-
6	Human Resources	-	-	-	-	-	-	-	-
7	Environmental & Safety	-	-	-	-	-	-	-	-
8	Information Technology	-	-	-	-	-	-	-	-
9	Distribution	3	3	3	3	3	3	3	3
10	Energy Solution & External Relations	-	-	-	-	-	-	-	-
11	Finance and Regulatory	-	-	-	-	-	-	-	-
12	Transmission	-	-	-	-	-	-	-	-
13	Corporate	-	-	-	-	-	-	-	-
14									
15	Total FTE	3	3	3	3	3	3	3	3
16									
17	Affiliation Summary								
18	COPE	-	-	-	-	-	-	-	-
19	IBEW	2	2	2	2	2	2	2	2
20	M&E	1	1	1	1	1	1	1	1
21	Total FTE	3	3	3	3	3	3	3	3

FortisBC Energy Inc.
Fort Nelson - Historic and Forecast FTE by Business Unit and Affiliation

Line no.	Business Unit & Affiliation	2006	2007	2008	2009	2010	Projected 2011	Forecast 2012	Forecast 2013
1	Energy Supply & Resource Development								
2	COPE	-	-	-	-	-	-	-	-
3	IBEW	-	-	-	-	-	-	-	-
4	M&E	-	-	-	-	-	-	-	-
5		-	-	-	-	-	-	-	-
6	Facilities								
7	COPE	-	-	-	-	-	-	-	-
8	IBEW	-	-	-	-	-	-	-	-
9	M&E	-	-	-	-	-	-	-	-
10		-	-	-	-	-	-	-	-
11	Operations Engineering								
12	COPE	-	-	-	-	-	-	-	-
13	IBEW	-	-	-	-	-	-	-	-
14	M&E	-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-
16	Operations Support								
17	COPE	-	-	-	-	-	-	-	-
18	IBEW	-	-	-	-	-	-	-	-
19	M&E	-	-	-	-	-	-	-	-
20		-	-	-	-	-	-	-	-
21	Customer Service								
22	COPE	-	-	-	-	-	-	-	-
23	IBEW	-	-	-	-	-	-	-	-
24	M&E	-	-	-	-	-	-	-	-
25		-	-	-	-	-	-	-	-
26	Human Resources								
27	COPE	-	-	-	-	-	-	-	-
28	IBEW	-	-	-	-	-	-	-	-
29	M&E	-	-	-	-	-	-	-	-
30		-	-	-	-	-	-	-	-
31	Environmental & Safety								
32	COPE	-	-	-	-	-	-	-	-
33	IBEW	-	-	-	-	-	-	-	-
34	M&E	-	-	-	-	-	-	-	-
35		-	-	-	-	-	-	-	-
36	Information Technology								
37	COPE	-	-	-	-	-	-	-	-
38	IBEW	-	-	-	-	-	-	-	-
39	M&E	-	-	-	-	-	-	-	-
40		-	-	-	-	-	-	-	-
41	Distribution								
42	COPE	-	-	-	-	-	-	-	-
43	IBEW	2	2	2	2	2	2	2	2
44	M&E	1	1	1	1	1	1	1	1
45		3	3	3	3	3	3	3	3
46	Energy Solution & External Relations								
47	COPE	-	-	-	-	-	-	-	-
48	IBEW	-	-	-	-	-	-	-	-
49	M&E	-	-	-	-	-	-	-	-
50		-	-	-	-	-	-	-	-
51	Finance and Regulatory								
52	COPE	-	-	-	-	-	-	-	-
53	IBEW	-	-	-	-	-	-	-	-
54	M&E	-	-	-	-	-	-	-	-
55		-	-	-	-	-	-	-	-
56	Transmission								
57	COPE	-	-	-	-	-	-	-	-
58	IBEW	-	-	-	-	-	-	-	-
59	M&E	-	-	-	-	-	-	-	-
60		-	-	-	-	-	-	-	-
61	Corporate								
62	COPE	-	-	-	-	-	-	-	-
63	IBEW	-	-	-	-	-	-	-	-
64	M&E	-	-	-	-	-	-	-	-
65		-	-	-	-	-	-	-	-
66									
67	Total FTE	3	3	3	3	3	3	3	3

Appendix D-5

HISTORIC SUMMARIES

FortisBC Energy Inc
UTILITY INCOME AND EARNED RETURN
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	ENERGY VOLUMES (TJ)															
2	Sales	116,140	112,775	3,365	116,776	112,775	4,001	115,223	112,010	3,213	108,575	113,966	(5,391)	113,863	112,775	1,088
3	Transportation	98,287	96,302	1,985	95,397	96,302	(905)	91,435	98,081	(6,646)	85,478	86,856	(1,378)	90,743	88,336	2,407
4																
5	Average Rate per GJ															
6	Sales	$ 13.539	$ 12.774	$ 0.765	$ 11.832	$ 12.774	$ (0.942)	$ 12.498	$ 12.548	$ (0.050)	$ 14.892	$ 11.067	$ 3.825	$ 12.755	$ 10.861	$ 1.894
7	Transportation	$ 0.751	$ 0.768	$ (0.017)	$ 0.775	$ 0.768	$ 0.007	$ 0.795	$ 0.746	$ 0.049	$ 0.848	$ 0.853	$ (0.005)	$ 0.844	$ 0.891	$ (0.047)
8	Average	$ 7.677	$ 7.244	$ 0.433	$ 6.860	$ 7.244	$ (0.384)	$ 7.320	$ 7.038	$ 0.282	$ 8.706	$ 6.649	$ 2.057	$ 7.472	$ 6.482	$ 0.990
9																
10	UTILITY REVENUE															
11	Sales - Existing Rates	$ 1,555,107	$ 1,440,644	$ 114,463	$ 1,390,101	$ 1,367,086	$ 23,015	$ 1,432,963	$ 1,405,491	$ 27,472	$ 1,622,703	$ 1,261,214	$ 361,489	$ 1,452,306	$ 1,224,870	$ 227,436
12	- Increase / (Decrease)	17,318		17,318	(8,416)		(8,416)	7,091		7,091						
13	Transportation - Existing Rates	71,360	73,919	(2,559)	75,080	64,912	10,168	71,737	73,168	(1,431)	73,324	74,110	(786)	76,544	78,672	(2,128)
14	- Increase / (Decrease)	2,458		2,458	(1,193)		(1,193)	980		980						
15	RSAM Revenue		9,901	(9,901)		7,775	(7,775)		12,967	(12,967)		(4,559)	4,559	-	(1,125)	1,125
16	Other Operating Revenue	24,837	22,696	2,141	24,910	22,044	2,866	23,701	21,834	1,867	23,444	20,941	2,503	22,455	21,828	627
17	**Total Revenue**	1,671,080	1,547,160	123,920	1,480,482	1,461,817	18,665	1,536,472	1,513,460	23,012	1,719,471	1,351,706	367,765	1,551,305	1,324,245	227,060
18	Cost of Gas Sold (Including Gas Lost)	1,151,571	1,029,444	122,127	966,880	963,275	3,605	1,021,804	997,718	24,086	1,187,999	818,403	369,596	987,970	762,338	225,632
19	**Gross Margin**	519,509	517,716	1,793	513,602	498,542	15,060	514,668	515,742	(1,074)	531,472	533,303	(1,831)	563,335	561,907	1,428
20																
21	Operation and Maintenance (incl Shared Svc Cost Allocation)	167,091	150,223	16,868	169,272	149,564	19,708	169,802	156,208	13,594	173,138	162,026	11,112	177,559	177,614	(55)
22	Transportation Costs															
23	Operating Leases	1,804	1,872	(68)	1,993	2,008	(15)	1,988	1,988	-	1,804	1,804	-			
24	Property and Sundry Taxes	41,379	41,379	-	44,452	44,452	-	44,635	44,635	-	47,593	47,593	-	49,193	49,193	-
25	Depreciation and Amortization	83,894	80,466	3,428	84,771	75,261	9,510	84,110	74,876	9,234	89,685	79,670	10,015	96,931	97,158	(227)
28	Removal Cost Provision															-
29	IFRS Revenue Requirement Adjustment															
30	Revenue Deficiency Deferred															
31	Interest on Subordinated Debt															
32	NSP Provision													5,963	8,343	(2,380)
34	Utility Income Before Income Taxes	225,341	243,776	(18,435)	213,114	227,257	(14,143)	214,133	238,035	(23,902)	219,252	242,210	(22,958)	233,689	229,599	4,090
35																
36	Income Taxes	38,977	45,197	(6,220)	30,897	34,402	(3,505)	26,760	33,451	(6,691)	28,314	29,551	(1,237)	33,395	31,152	2,243
37	**EARNED RETURN**	$ 186,364	$ 198,579	$ (12,215)	$ 182,217	$ 192,855	$ (10,638)	$ 187,373	$ 204,584	$ (17,211)	$ 190,938	$ 212,659	$ (21,721)	$ 200,294	$ 198,447	$ 1,847
38	**UTILITY RATE BASE**	$ 2,505,910	$ 2,442,352	$ 63,558	$ 2,474,218	$ 2,426,180	$ 48,038	$ 2,505,027	$ 2,474,447	$ 30,580	$ 2,541,323	$ 2,462,143	$ 79,180	$ 2,534,454	$ 2,525,219	$ 9,236
39																
40	**RETURN ON RATE BASE**	7.44%	8.13%	-0.69%	7.36%	7.95%	-0.59%	7.48%	8.27%	-0.79%	7.51%	8.64%	-1.13%	7.90%	7.86%	0.04%

FortisBC Energy (Vancouver Island) Inc
UTILITY INCOME AND EARNED RETURN
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	ENERGY VOLUMES (TJ)															
2	Sales	12,131	11,810	320	12,262	12,295	(33)	12,666	12,671	(5)	12,264	12,309	(45)	12,241	11,491	750
3	Transportation	21,361	16,334	5,027	21,505	23,302	(1,797)	20,644	22,342	(1,698)	22,946	18,869	4,077	22,309	19,526	2,783
4																
5	Average Rate per GJ															
6	Sales	$ 12.819	$ 12.875	$ (0.056)	$ 13.515	$ 13.533	$ (0.018)	$ 14.168	$ 14.145	$ 0.023	$ 13.565	$ 14.660	$ (1.095)	$ 11.297	$ 10.901	$ 0.396
7	Transportation	$ 0.892	$ 1.248	$ (0.356)	$ 0.966	$ 0.984	$ (0.019)	$ 1.048	$ 1.026	$ 0.022	$ 0.967	$ 1.278	$ (0.311)	$ 0.926	$ 1.210	$ (0.284)
8	Average	$ 5.212	$ 6.127	$ (0.915)	$ 5.523	$ 5.318	$ 0.204	$ 6.037	$ 5.774	$ 0.263	$ 5.355	$ 6.561	$ (1.206)	$ 4.601	$ 4.800	$ (0.199)
9																
10	UTILITY REVENUE															
11	Sales - Existing Rates	$ 155,504	$ 152,055	$ 3,449	$ 165,723	$ 166,384	$ (661)	$ 179,454	$ 179,230	$ 224	$ 179,501	$ 180,453	$ (952)	$ 179,445	$ 169,789	$ 9,656
12	- Increase / (Decrease)										(13,145)		(13,145)	(41,155)	(44,527)	3,372
13	Transportation - Existing Rates	19,055	20,384	(1,329)	20,769	22,937	(2,168)	21,644	22,929	(1,285)	22,194	24,106	(1,912)	20,669	23,621	(2,952)
14	- Increase / (Decrease)															
15	RSAM Revenue															
16	Other Revenue	71,162	37,196	33,966	34,879	36,274	(1,396)	40,857	44,266	(3,409)	19,045	22,889	(3,844)	40,595	17,905	22,690
17	**Total Revenue**	245,721	209,634	36,087	221,371	225,594	(4,224)	241,955	246,425	(4,470)	207,595	227,447	(19,852)	199,554	166,788	32,766
18	Cost of Gas Sold (Including Gas Lost)	137,670	99,494	38,175	99,149	100,937	(1,788)	109,595	107,258	2,337	99,314	99,355	(41)	98,628	74,343	24,285
19	**Gross Margin**	108,051	110,140	(2,089)	122,222	124,657	(2,435)	132,360	139,167	(6,807)	108,281	128,092	(19,811)	100,926	92,445	8,481
20																
21	Operation and Maintenance (incl Shared Svc Cost Allocation)	24,423	24,423	-	25,168	25,168	-	25,922	25,671	250	26,178	26,178	-	26,859	26,859	-
22	Transportation Costs	4,786	4,613	173	4,101	4,829	(728)	3,375	4,054	(679)	3,977	4,012	(35)	4,015	4,019	(4)
23	Operating Leases	1,748	1,748	-	1,748	1,748	-	1,748	1,748	-	828	828	-	-	-	-
24	Property and Sundry Taxes	7,211	7,014	197	7,413	7,553	(140)	7,873	7,838	35	8,449	8,488	(39)	9,119	9,039	80
25	Depreciation and Amortization	16,786	15,638	1,148	16,347	16,189	158	18,304	18,283	21	23,017	19,122	3,895	19,202	25,975	(6,773)
26	Amortization of CIAC	247	247	-	995	995	-	1,991	1,991	-		1,990	(1,990)		(4,420)	4,420
27	Amortization of Deferreds	5,287	4,749	537	4,858	4,755	103	3,756	3,715	41		5,664	(5,664)		(7,690)	7,690
28	Removal Costs													343	343	-
29	IFRS Revenue Requirement Adjustment													1,400	1,400	-
30	Revenue Deficiency Deferred	3,009	6,904	(3,895)	11,513	14,011	(2,498)	14,161	20,593	(6,432)		13,571	(13,571)			-
31	Interest on Subordinated Debt	3,020	3,954	(934)	3,200	3,214	(14)	1,905	2,502	(597)		1,282	(1,282)		261	(261)
32	NSP Provision			-			-			-			-			-
33	Utility Income Before Income Taxes	41,534	40,849	685	46,879	46,195	684	53,326	52,773	553	45,831	46,957	(1,126)	39,989	36,660	3,328
34																
35	Income Taxes	7,252	11,228	(3,976)	14,180	15,795	(1,615)	15,241	17,663	(2,422)	13,342	13,421	(79)	1,133	1,665	(532)
36	**ALLOWED EARNED RETURN**	$ 34,283	$ 29,621	$ 4,662	$ 32,700	$ 30,401	$ 2,299	$ 38,085	$ 35,110	$ 2,975	$ 36,594	$ 33,537	$ 3,057	$ 38,856	$ 34,995	$ 3,861
37	**UTILITY RATE BASE**	$ 477,600	$ 464,180	$ 13,420	$ 474,714	$ 478,699	$ (3,985)	$ 514,175	$ 511,422	$ 2,753	$ 539,845	$ 532,925	$ 6,920	$ 553,966	$ 547,661	$ 6,305
38																
39	**RETURN ON RATE BASE Before VINGPA Adjustment**	7.18%	6.75%	0.43%	6.87%	6.74%	0.13%	7.36%	7.23%	0.13%	7.12%	6.64%	0.48%	7.35%	6.73%	0.62%
40	**RETURN ON RATE BASE After VINGPA Adjustment**										6.78%			7.01%		

FortisBC Energy (Whistler) Inc
UTILITY INCOME AND EARNED RETURN
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[2]	2007 Actual	2007 Variance	2008 Approved[2]	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	ENERGY VOLUMES (TJ)															
2	Sales		734		742	742	-	709	709	-	747.8	629	118	759	765	(6)
3	Transportation															
4																
5	Average Rate per GJ															
6	Sales		$ 14.133		$ 14.142	$ 14.142	$ -	$ 14.154	$ 14.154	$ -	$ 23.420	$ 23.273	$ 0.147	$ 18.311	$ 17.945	$ 0.366
7	Transportation															
8	Average		$ 14.133		$ 14.142	$ 14.142	$ -	$ 14.154	$ 14.154	$ -	$ 23.420	$ 23.273	$ 0.147	$ 18.311	$ 17.945	$ 0.366
9																
10	UTILITY REVENUE															
11	Sales - Existing Rates		$ 10,369		$ 10,495	$ 10,495	$ -	$ 10,041	$ 10,041	$ -	$ 10,583	$ 10,175	$ 408	$ 17,702	$ 9,560	$ 8,142
12	- Increase / (Decrease)										6,930	4,475	2,455	(3,803)	4,177	(7,979)
13	Transportation - Existing Rates															
14	- Increase / (Decrease)															
15	RSAM Revenue														283	(283)
16	Other Revenue		39		(72)	(72)	-	8	8	-	31	660	(630)	56	30	26
17	**Total Revenue**		10,408		10,423	10,423	-	10,049	10,049	-	17,544	15,311	2,233	13,955	14,049	(94)
18	Cost of Gas Sold (Including Gas Lost)		7,497		7,596	7,596	-	7,278	7,278	-	11,544	9,880	1,664	5,079	5,165	(86)
19	**Gross Margin**		2,911		2,827	2,827	-	2,771	2,771	-	6,000	5,431	570	8,876	8,884	(8)
20																
21	Operation and Maintenance (incl Shared Svc Cost Allocation)		725		697	697	-	808	808	-	724	700	24	730	654	76
22	Transportation Costs										2,050	1,995	55	2,430	2,430	-
23	Operating Leases															
24	Property and Sundry Taxes		304		285	285	-	285	285	-	369	369	-	285	285	-
25	Depreciation and Amortization		498		513	513	-	497	497	-	501	516	(14)	385	353	31
26	Amortization of CIAC											-	-		(5)	5
27	Amortization of Deferreds		4		7	7	-				(78)	(78)	-	1,509	1,509	-
28	Removal Costs													5	5	-
29	IFRS Revenue Requirement Adjustment													(6)		(6)
30	Revenue Deficiency Deferred															
31	Interest on Subordinated Debt															
32	NSP Provision														(6)	
33	Utility Income Before Income Taxes		1,379		1,325	1,325	-	1,181	1,181	-	2,434	1,929	505	3,539	3,658	(120)
34																
35	Income Taxes		231		232	232	-	190	190	-	(344)	(249)	(95)	653	671	(18)
36	**EARNED RETURN**		$ 1,146		$ 1,093	$ 1,093	$ -	$ 991	$ 991	$ -	$ 2,778	$ 2,178	$ 600	$ 2,886	$ 2,987	$ (102)
37	**UTILITY RATE BASE**		$ 17,040		$ 16,830	$ 16,830	$ -	$ 16,782	$ 16,782	$ -	$ 38,816	$ 31,518	$ 7,298	$ 42,568	$ 45,400	$ (2,832)
38																
39	**RETURN ON RATE BASE**		6.72%		6.49%	6.49%		5.91%	5.91%		7.16%	6.91%	0.25%	6.78%	6.58%	0.20%

Notes:
1) No Approved numbers for 2006
2) 2007 and 2008 are not test years. FEW had a ROE deferral account that allowed it to earn its regulated return from its last test year in 2005

Fort Nelson
UTILITY INCOME AND EARNED RETURN
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[1]	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved[1]	2010 Actual	2010 Variance
1	ENERGY VOLUMES (TJ)															
2	Sales		557			552		589	541	48	554	552	2		560	
3	Transportation		349			264		265	210	55	14	69	(55)		55	
4																
5	Average Rate per GJ															
6	Sales		$ 9.230			$ 8.476		$ 8.711	$ 9.580	$ (0.869)	$ 10.594	$ 9.074	$ 1.520		$ 8.554	
7	Transportation		$ 0.885			$ 0.890		$ 1.112	$ 1.100	$ 0.012	$ 3.014	$ 2.043	$ 0.971		$ 2.127	
8	Average		$ 6.015			$ 6.022		$ 6.356	$ 7.209	$ (0.853)	$ 10.410	$ 8.293	$ 2.117		$ 7.880	
9																
10	UTILITY REVENUE															
11	Sales - Existing Rates		$ 5,141			$ 4,679		$ 5,134	$ 5,183	$ (49)	$ 5,868	$ 5,009	$ 859		$ 4,790	
12	- Increase / (Decrease)															
13	Transportation - Existing Rates		309			235		295	231	64	42	141	(99)		117	
14	- Increase / (Decrease)															
15	RSAM Revenue		114			176			174	(174)	-	(86)	86		(61)	
16	Other Operating Revenue		33			35		37	35	2	45	32	13		29	
17	**Total Revenue**		5,597			5,125		5,466	5,623	(157)	5,955	5,096	859		4,875	
18	Cost of Gas Sold (Including Gas Lost)		4,251			3,786		4,054	4,234	(180)	4,476	3,764	712		3,409	
19	**Gross Margin**		1,346			1,339		1,412	1,389	23	1,479	1,332	147		1,466	
20																
21	Operation and Maintenance (incl Shared Svc Cost Allocation)		688			701		652	599	53	664	658	6		680	
22	Transportation Costs															
23	Operating Leases															
24	Property and Sundry Taxes		98			97		125	125	-	157	157	-		158	
25	Depreciation and Amortization		116			127		198	154	44	191	162	29		220	
26	Amortization of CIAC															
27	Amortization of Deferreds															
28	Removal Costs															
29	IFRS Revenue Requirement Adjustment															
30	Revenue Deficiency Deferred															
31	Interest on Subordinated Debt															
32	NSP Provision															
33	Utility Income Before Income Taxes		444			413		437	511	(74)	467	355	112		409	
34																
35	Income Taxes		60			46		49	61	(12)	64	21	43		52	
36	**EARNED RETURN**		$ 384			$ 367		$ 388	$ 450	$ (62)	$ 402	$ 334	$ 68		$ 357	
37	**UTILITY RATE BASE**		$ 4,825			$ 5,048		$ 5,154	$ 5,093	$ 61	$ 5,405	$ 5,055	$ 350		$ 5,410	
38																
39	**RETURN ON RATE BASE**		7.97%			7.28%		7.53%	8.83%	-1.30%	7.43%	6.60%	0.83%		6.60%	

Notes:
1) No Approved numbers for 2006, 2007, 2010

FortisBC Energy Inc
INCOME TAXES
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance
1	CALCULATION OF INCOME TAXES						
2	Utility Income before Taxes	$ 225,340	$ 243,776	$ (18,436)	$ 213,113	$ 227,257	$ (14,144)
3	Deduct - Interest on Debt	(109,168)	(107,512)	(1,656)	(109,714)	(108,232)	(1,482)
4	Add- Non-Tax Ded. Expense (Net)	(1,348)	(1,409)	61	(2,290)	(2,326)	36
5	Accounting Income Before Tax	114,824	134,855	(20,031)	101,109	116,699	(15,590)
6	Add (Deduct) - Timing Differences	(6,115)	(7,295)	1,180	(7,482)	(12,450)	4,968
7							
8	Current Income Tax Rate	34.12%	34.12%	-	33.00%	33.00%	-
9	1 - Current Income Tax Rate	65.88%	65.88%	-	67.00%	67.00%	-
10							
11	**Taxable Income**	$ 108,709	$ 127,560	$ (18,851)	$ 93,627	$ 104,249	$ (10,622)
12	Taxable Income Adjustment - SCP Landscaping Deduction						
13	Taxable Income Adjustment - Tax on SCP Landscaping						
14							
15	Adjusted Taxable Income before Tax						
16							
17	Income Tax						
18	Current	$ 37,092	$ 43,523	$ (6,431)	$ 30,897	$ 34,402	$ (3,505)
19	Large Corporation Tax	1,885	1,674	211			
20							
21	Less Tax Recovery from Loss Carryback						
22	Previous Year Adjustment						
23	**Total Income Tax**	$ 38,977	$ 45,197	$ (6,220)	$ 30,897	$ 34,402	$ (3,505)

Line no.	Particulars	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	CALCULATION OF INCOME TAXES									
2	Utility Income before Taxes	$ 214,133	$ 238,035	$ (23,902)	$ 219,252	$ 242,210	$ (22,958)	$ 233,689	$ 229,599	$ 4,090
3	Deduct - Interest on Debt	(111,799)	(110,806)	(993)	(110,954)	(108,753)	(2,201)	(103,989)	(103,862)	(127)
4	Add- Non-Tax Ded. Expense (Net)	(2,676)	(2,618)	(58)	328	419	(91)	(2,069)	(1,902)	(167)
5	Accounting Income Before Tax	99,658	124,611	(24,953)	108,626	133,876	(25,250)	127,631	123,835	3,796
6	Add (Deduct) - Timing Differences	(14,707)	(18,417)	3,710	(14,248)	(35,371)	21,123	(4,858)	(8,927)	4,069
7										
8	Current Income Tax Rate	31.50%	31.50%	-	30.00%	30.00%	-	28.50%	28.50%	-
9	1 - Current Income Tax Rate	68.50%	68.50%	-	70.00%	70.00%	-	71.50%	71.50%	-
10										
11	**Taxable Income**	$ 84,951	$ 106,194	$ (21,243)	$ 94,378	$ 98,505	$ (4,127)	$ 122,773	$ 114,908	$ 7,865
12	Taxable Income Adjustment - SCP Landscaping Deduction							(7,834)	(7,834)	-
13	Taxable Income Adjustment - Tax on SCP Landscaping							2,233	2,233	-
14										
15	Adjusted Taxable Income before Tax							117,172	109,307	7,865
16										
17	Income Tax									
18	Current	$ 26,760	$ 33,451	$ (6,691)	$ 28,314	$ 29,551	$ (1,237)	$ 33,395	$ 31,152	$ 2,243
19	Large Corporation Tax									
20										
21	Less Tax Recovery from Loss Carryback									
22	Previous Year Adjustment									
23	**Total Income Tax**	$ 26,760	$ 33,451	$ (6,691)	$ 28,314	$ 29,551	$ (1,237)	$ 33,395	$ 31,152	$ 2,243

FortisBC Energy (Vancouver Island) Inc
INCOME TAXES
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	CALCULATION OF INCOME TAXES															
2	Achieved Return on Equity for Tax Purpose (Before Tax)	$ 20,990	$ 29,054	$ (8,064)	$ 29,524	$ 31,866	$ (2,341)	$ 30,681	$ 31,918	$ (1,237)	$ 33,247	$ 33,247	$ -	$ 28,380	$ 34,995	$ (6,615)
3	Total Additions	48,590	44,021	4,569	61,335	58,196	3,140	66,755	67,539	(784)	61,857	62,202	(345)	(9,220)	(14,956)	5,736
4	Total Deductions	47,600	39,302	8,298	49,301	44,689	4,612	48,128	42,453	5,675	50,631	48,135	2,496	15,183	15,666	(483)
5																
6	Current Income Tax Rate	33.00%	33.00%	-	34.12%	34.12%	-	31.00%	31.00%	-	30.00%	30.00%	-	28.50%	28.50%	-
7	1 - Current Income Tax Rate	67.00%	67.00%	-	65.88%	65.88%	-	69.00%	69.00%	-	70.00%	70.00%	-	71.50%	71.50%	-
8																
9	**Taxable Income**	$ 21,977	$ 33,772	$ (11,795)	$ 41,558	$ 45,372	$ (3,814)	$ 49,163	$ 56,976	$ (7,813)	$ 44,473	$ 47,314	$ (2,841)	$ 3,977	$ 4,373	$ (396)
10	Taxable Income Adjustment - SCP Landscaping Deduction															
11	Taxable Income Adjustment - Tax on SCP Landscaping															
12																
15	Income Tax - Current															
16	Current	$ 7,252	$ 11,145	$ (3,892)	$ 14,180	$ 15,544	$ (1,365)	$ 15,241	$ 17,663	$ (2,422)	$ 13,342	$ 14,194	$ (852)	$ 1,133	$ 1,665	$ (532)
17	Large Corporation Tax		83	(83)												
18																
19	Less Tax Recovery from Loss Carryback															
20	Previous Year Adjustment					250	(250)					(774)	774		(78)	78
21	**Total Income Tax**	$ 7,252	$ 11,228	$ (3,975)	$ 14,180	$ 15,795	$ (1,615)	$ 15,241	$ 17,663	$ (2,422)	$ 13,342	$ 13,421	$ (79)	$ 1,133	$ 1,588	$ (454)

FortisBC Energy (Whistler) Inc
INCOME TAXES
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[2]	2007 Actual	2007 Variance	2008 Approved[2]	2008 Actual	2008 Variance	2009 Approved[3]	2009 Actual[3]	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	CALCULATION OF INCOME TAXES															
2	Accounting Income Before Tax		$ 863		$ 861	$ 861	$ -	$ 676	$ 676	$ -	$ 1,473	$ 1,554	$ (80)	$ 2,381	$ 2,456	$ (74)
3	Total Additions		756		792	792	-	725	725	-	(76)	545	(621)	1,041	2,607	(1,566)
4	Total Deductions		844		826	826	-	787	787	-	(5,320)	2,905	(8,225)	1,130	2,709	(1,579)
5																
6	Current Income Tax Rate		33.00%		34.12%	34.12%	-	31.00%	31.00%	-	30.00%	30.00%	-	28.50%	28.50%	-
7	1 - Current Income Tax Rate		67.00%		65.88%	65.88%	-	69.00%	69.00%	-	70.00%	70.00%	-	71.50%	71.50%	-
8																
9	**Taxable Income**		$ 776		$ 827	$ 827	$ -	$ 614	$ 614	$ -			$ -	$ 2,292	$ 2,354	$ (62)
10	Taxable Income Adjustment - SCP Landscaping Deduction															
11	Taxable Income Adjustment - Tax on SCP Landscaping															
12																
15	Income Tax															
16	Current		256		282	282	-	190	190	-				653	671	(18)
17	Large Corporation Tax															
18																
19	Less Tax Recovery from Loss Carryback										(344)	(249)	(95)			
20	Previous Year Adjustment		(25)		(50)	(50)	-									
21	**Total Income Tax**		$ 231		$ 232	$ 232	$ -	$ 190	$ 190	$ -	$ (344)	$ (249)	$ (95)	$ 653	$ 671	$ (18)

Notes:
1) No Approved numbers for 2006
2) 2007 and 2008 are not test years. FEW had a ROE deferral account that allowed it to earn its regulated return from its last test year in 2005
3) No taxable income due to Loss Carryback

Fort Nelson
INCOME TAXES
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[1]	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved[1]	2010 Actual	2010 Variance
1	CALCULATION OF INCOME TAXES															
2	Utility Income before Taxes		$ 444			$ 413		$ 437	$ 511	$ (74)	$ 467	$ 355	$ 112		$ 409	
3	Deduct - Interest on Debt		(209)			(214)		(231)	(231)	-	(232)	(222)	(10)		(217)	
4	Add- Non-Tax Ded. Expense (Net)		1			1			32	(32)	6	17	(11)			
5	Accounting Income Before Tax		236			200		206	312	(106)	241	150	91		192	
6	Add (Deduct) - Timing Differences		(55)			(66)		(49)	(118)	69	(27)	(80)	53		(9)	
7																
8	Current Income Tax Rate		34.12%			34.12%		31.50%	31.50%	-	30.00%	30.00%	-		28.50%	
9	1 - Current Income Tax Rate		65.88%			65.88%		68.50%	68.50%	-	70.00%	70.00%	-		71.50%	
10																
11	**Taxable Income**		$ 181			$ 134		$ 157	$ 194	$ (37)	$ 214	$ 70	$ 144		$ 183	
12	Taxable Income Adj - SCP Landscaping Deduction															
13	Taxable Income Adj - Tax on SCP Landscaping															
14																
17	Income Tax															
18	Current		62			46		49	61	(12)	64	21	43		52	
19	Large Corporation Tax		(2)													
20																
21	Less Tax Recovery from Loss Carryback															
22	Previous Year Adjustment															
23	**Total Income Tax**		$ 60			$ 46		$ 49	$ 61	$ (12)	$ 64	$ 21	$ 43		$ 52	

Notes:
1) No Approved numbers for 2006, 2007, 2010

FortisBC Energy Inc
RETURN ON CAPITAL
($000)

Line		2006			2007			2008			2009			2010		
no.	Particulars	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance
1	Unfunded Debt	$ 195,922	$ 154,478	$ 41,444	$ 137,943	$ 106,491	$ 31,452	$ 254,136	$ 234,262	$ 19,874	$ 147,307	$ 95,848	$ 51,459	$ 36,824	$ 31,284	$ 5,541
2	Proportion	7.82%	6.32%	1.50%	5.58%	4.39%	1.19%	10.15%	9.47%	0.68%	5.80%	3.89%	1.91%	1.45%	1.24%	0.21%
3	Rate of Return	0.40%	4.00%	-3.60%	4.75%	4.75%	-	5.00%	5.00%	-	4.25%	4.25%	-	2.25%	2.25%	-
4	Return Component	0.31%	0.25%	0.06%	0.27%	0.21%	0.06%	0.51%	0.47%	0.04%	0.25%	0.17%	0.08%	0.03%	0.03%	0.01%
5																
6	Long-Term Debt	$ 1,432,919	$ 1,433,051	$ (132)	$ 1,470,051	$ 1,470,283	$ (232)	$ 1,373,881	$ 1,373,881	$ -	$ 1,504,299	$ 1,504,299	$ -	$ 1,483,848	$ 1,483,848	$ -
7	Proportion	57.18%	58.68%	-1.50%	59.41%	60.60%	-1.19%	54.84%	55.52%	-0.68%	59.19%	61.10%	-1.91%	58.55%	58.76%	-0.21%
8	Rate of Return	7.07%	7.07%	-	7.02%	7.02%	-	7.21%	7.21%	-	6.96%	6.96%	-	6.95%	6.95%	-
9	Return Component	4.04%	4.15%	-0.11%	4.17%	4.25%	-0.08%	3.96%	4.00%	-0.04%	4.12%	4.25%	-0.13%	4.07%	4.09%	-0.01%
10																
11	Common Equity	$ 877,069	$ 854,823	$ 22,246	$ 866,224	$ 849,406	$ 16,818	$ 877,010	$ 866,304	$ 10,706	$ 889,717	$ 861,996	$ 27,721	$ 1,013,782	$ 1,010,087	$ 3,695
12	Proportion	35.00%	35.00%	-	35.01%	35.01%	-	35.01%	35.01%	-	35.01%	35.01%	-	40.00%	40.00%	-
13	Rate of Return	8.80%	10.65%	-1.85%	8.37%	9.96%	-1.59%	8.62%	10.83%	-2.21%	8.99%	12.05%	-3.06%	9.50%	9.36%	0.14%
14	Return Component	3.08%	3.73%	-0.65%	2.93%	3.49%	-0.56%	3.02%	3.79%	-0.77%	3.15%	4.22%	-1.07%	3.80%	3.75%	0.05%
15																
16	**Return on rate base**	7.44%	8.13%	-0.69%	7.36%	7.95%	-0.59%	7.48%	8.27%	-0.79%	7.51%	8.64%	-1.13%	7.90%	7.86%	0.04%
17	**Utility rate base**	$ 2,505,910	$ 2,442,352	$ 63,558	$ 2,474,218	$ 2,426,180	$ 48,038	$ 2,505,027	$ 2,474,447	$ 30,580	$ 2,541,323	$ 2,462,143	$ 79,180	$ 2,534,454	$ 2,525,219	$ 9,236

FortisBC Energy (Vancouver Island) Inc
RETURN ON CAPITAL
($000)

Line		2006			2007			2008			2009			2010		
no.	Particulars	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance
1	Unfunded Debt	$ 60,440	$ 13,367	$ 47,073	$ 14,241	$ 18,220	$ (3,978)	$ 59,215	$ 48,722	$ 10,493	$ 62,967	$ 58,815	$ 4,152	$ 42,721	$ 55,809	$ (13,088)
2	Proportion	12.65%	2.88%	9.77%	3.00%	3.81%	-0.81%	11.52%	9.53%	1.99%	11.66%	11.04%	0.62%	7.71%	10.18%	-2.47%
3	Rate of Return	4.25%	4.86%	-0.61%	5.50%	5.18%	0.32%	6.06%	5.32%	0.74%	1.50%	2.86%	-1.36%	2.50%	7.08%	-4.58%
4	Return Component	0.54%	0.14%	0.40%	0.17%	0.20%	-0.03%	0.70%	0.51%	0.19%	0.17%	0.32%	-0.15%	0.19%	0.72%	-0.53%
5																
6	Long-Term Debt	$ 250,000	$ 265,142	$ (15,142)	$ 270,587	$ 269,000	$ 1,587	$ 249,290	$ 258,131	$ (8,841)	$ 260,940	$ 260,940	$ -	$ 289,659	$ 272,787	$ 16,872
7	Proportion	52.35%	57.12%	-4.77%	57.00%	56.19%	0.81%	48.48%	50.47%	-1.99%	48.34%	48.96%	-0.62%	52.29%	49.82%	2.47%
8	Rate of Return	6.13%	4.91%	1.22%	5.40%	5.19%	0.21%	6.05%	5.94%	0.11%	5.96%	5.09%	0.87%	5.95%	4.62%	1.33%
9	Return Component	3.21%	2.81%	0.40%	3.08%	2.92%	0.16%	2.93%	3.00%	-0.07%	2.88%	2.49%	0.39%	3.11%	2.30%	0.81%
10																
11	Common Equity	$ 167,160	$ 185,672	$ (18,512)	$ 189,886	$ 191,480	$ (1,594)	$ 205,670	$ 204,569	$ 1,101	$ 215,938	$ 213,170	$ 2,768	$ 221,586	$ 219,064	$ 2,522
12	Proportion	35.00%	40.00%	-5.00%	40.00%	40.00%	-	40.00%	40.00%	-	40.00%	40.00%	-	40.00%	40.00%	-
13	Rate of Return	9.53%	9.50%	0.03%	9.07%	9.07%	-	9.32%	9.32%	-	9.59%	9.59%	-	10.00%	10.00%	-
14	Return Component	3.34%	3.80%	-0.46%	3.63%	3.63%	-	3.73%	3.73%	-	3.84%	3.84%	-	4.00%	4.00%	-
15																
16	**Return on rate base**	7.18%	6.75%	0.43%	6.87%	6.74%	0.13%	7.36%	7.23%	0.13%	7.12%	6.64%	0.48%	7.35%	6.73%	0.62%
17	**Utility rate base**	$ 477,600	$ 464,180	$ 13,420	$ 474,714	$ 478,699	$ (3,985)	$ 514,175	$ 511,422	$ 2,753	$ 539,845	$ 532,925	$ 6,920	$ 553,966	$ 547,661	$ 6,305

FortisBC Energy (Whistler) Inc
RETURN ON CAPITAL
($000)

Line			2006			2007			2008			2009			2010	
no.	Particulars	Approved[1]	Actual	Variance	Approved[2]	Actual	Variance	Approved[2]	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance
1	Unfunded Debt		$ 3,076		$ 2,939	$ 2,939	$ -	$ 2,909	$ 2,909	$ -	$ 9,240	$ 3,777	$ 5,464	$ 5,541	$ 7,240	$ (1,699)
2	Proportion		18.05%		17.47%	17.47%	-	17.33%	17.33%	-	23.81%	11.98%	11.83%	13.02%	15.94%	-2.93%
3	Rate of Return		5.68%		4.00%	4.00%	-	4.00%	4.00%	-	5.10%	5.10%	-	2.90%	2.90%	-
4	Return Component		1.03%		0.70%	0.70%	-	0.69%	0.69%	-	1.21%	0.61%	0.60%	0.38%	0.46%	-0.08%
5																
6	Long-Term Debt		$ 8,000		$ 8,000	$ 8,000	$ -	$ 8,000	$ 8,000	$ -	$ 14,049	$ 15,134	$ (1,085)	$ 20,000	$ 20,000	$ -
7	Proportion		46.95%		47.53%	47.53%	-	47.67%	47.67%	-	36.19%	48.02%	-11.83%	46.98%	44.06%	2.93%
8	Rate of Return		4.90%		5.10%	5.10%	-	5.10%	5.10%	-	5.93%	5.90%	0.03%	5.11%	5.10%	0.01%
9	Return Component		2.30%		2.42%	2.42%	-	2.43%	2.43%	-	2.15%	2.83%	-0.68%	2.40%	2.25%	0.15%
10																
11	Common Equity		$ 5,964		$ 5,890	$ 5,890	$ -	$ 5,874	$ 5,874	$ -	$ 15,526	$ 12,608	$ 2,919	$ 17,027	$ 18,160	$ (1,133)
12	Proportion		35.00%		35.00%	35.00%	-	35.00%	35.00%	-	40.00%	40.00%	-	40.00%	40.00%	-
13	Rate of Return		9.69%		9.63%	9.63%	-	7.94%	7.94%	-	9.49%	8.63%	0.86%	10.00%	8.84%	1.16%
14	Return Component		3.39%		3.37%	3.37%	-	2.78%	2.78%	-	3.80%	3.45%	0.35%	4.00%	3.53%	0.47%
15																
16	**Return on rate base**		6.72%		6.49%	6.49%	-	5.91%	5.91%	-	7.16%	6.91%	0.25%	6.78%	6.58%	0.20%
17	**Utility rate base**		$ 17,040		$ 16,830	$ 16,830	$ -	$ 16,782	$ 16,782	$ -	$ 38,816	$ 31,518	$ 7,298	$ 42,568	$ 45,400	$ (2,832)

Notes:
1) No Approved numbers for 2006
2) 2007 and 2008 are not test years. FEW had a ROE deferral account that allowed it to earn its regulated return from its last test year in 2005

Fort Nelson
RETURN ON CAPITAL
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[1]	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved[1]	2010 Actual	2010 Variance
1	Unfunded Debt		$ 525			$ 678		$ 415	$ 375	$ 40	$ 478	$ 250	$ 228		$ 304	
2	Proportion		10.92%			13.43%		8.04%	7.36%	0.68%	8.84%	4.95%	3.89%		11.15%	
3	Rate of Return		3.25%			3.25%		5.00%	5.00%	-	4.25%	4.25%	-		4.25%	
4	Return Component		0.35%			0.44%		0.40%	0.37%	0.03%	0.38%	0.21%	0.17%		0.47%	
5																
6	Long-Term Debt		$ 2,603			$ 2,603		$ 2,935	$ 2,935	$ -	$ 3,035	$ 3,035	$ -		$ 2,942	
7	Proportion		54.08%			51.56%		56.95%	57.63%	-0.68%	56.15%	60.04%	-3.89%		53.84%	
8	Rate of Return		7.37%			7.37%		7.22%	7.22%	-	6.96%	6.96%	-		6.95%	
9	Return Component		3.99%			3.80%		4.11%	4.16%	-0.05%	3.91%	4.18%	-0.27%		3.74%	
10																
11	Common Equity		$ 1,685			$ 1,767		$ 1,804	$ 1,783	$ 21	$ 1,892	$ 1,770	$ 122		$ 2,164	
12	Proportion		35.00%			35.01%		35.01%	35.01%	-	35.01%	35.01%	-		35.01%	
13	Rate of Return		10.37%			8.68%		8.62%	12.28%	-3.66%	8.99%	6.31%	2.68%		7.14%	
14	Return Component		3.53%			3.04%		3.18%	4.30%	-1.12%	3.15%	2.21%	0.94%		2.50%	
15																
16	**Return on rate base**		7.97%			7.28%		7.53%	8.83%	-1.30%	7.43%	6.60%	0.83%		6.60%	
17	**Utility rate base**		$ 4,858			$ 5,048		$ 5,154	$ 5,093	$ 61	$ 5,405	$ 5,055	$ 350		$ 5,410	

Notes:
1) No Approved numbers for 2006, 2007, 2010

FortisBC Energy Inc
UTILITY RATE BASE
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	Gas Plant in Service, Beginning	$ 3,067,485	$ 3,020,622	$ 46,863	$ 3,140,710	$ 3,067,389	$ 73,321	$ 3,242,849	$ 3,140,066	$ 102,783	$ 3,339,098	$ 3,215,664	$ 123,434	$ 3,315,365	$ 3,302,151	$ 13,214
2	Adjustment - CPCNs / Opening Bal Adjt	74,143	46,768	27,375	104,936	72,677	32,259	105,683	73,984	31,699	12,855	101,926	(89,071)	138,029	86,711	51,318
3	Gas Plant in Service, Ending	3,141,628	3,067,389	74,239	3,245,646	3,140,066	105,580	3,348,532	3,214,050	134,482	3,442,274	3,317,590	124,684	3,453,394	3,388,862	64,532
4																
5	Accumulated Depreciation Beginning - Plant	(670,342)	(655,495)	(14,847)	(702,160)	(670,195)	(31,965)	(754,566)	(711,495)	(43,071)	(808,588)	(743,486)	(65,102)	(780,174)	(779,846)	(328)
6	Adjustment - CPCNs / Opening Bal Adjt	(1,523)	(14,700)	13,177	(42,137)	(41,300)	(837)	(10,768)	(31,991)	21,223	(60,589)	(36,360)	(24,229)	(55,191)	(67,668)	12,477
7	Accumulated Depreciation Ending - Plant	(671,865)	(670,195)	(1,670)	(744,297)	(711,495)	(32,802)	(765,334)	(743,486)	(21,848)	(869,177)	(779,846)	(89,331)	(835,365)	(847,514)	12,149
8																
9	Intangible Plant Opening	837	837	-	1,614	837	777	1,614	1,614	-	1,614	1,614	-	1,614	1,614	-
10	Adjustment - CPCNs / Opening Bal Adjt					777	(777)									
11	Intangible Plant Closing	837	837	-	1,614	1,614	-	1,614	1,614	-	1,614	1,614	-	1,614	1,614	-
12																
13	CIAC, Beginning	(144,667)	(148,612)	3,945	(151,597)	(162,075)	10,478	(148,423)	(150,600)	2,177	(148,423)	(161,636)	13,213	(176,845)	(163,384)	(13,461)
14	Adjustment - Opening Bal Adjt	(7,648)	13,463	(21,111)	20,435	11,475	8,960	261	(11,036)	11,297	1,595	(15,209)	16,804	(7,040)	(764)	(6,276)
15	CIAC, Ending	(137,019)	(162,075)	25,056	(131,162)	(150,600)	19,438	(148,162)	(161,636)	13,474	(146,828)	(176,845)	30,017	(183,885)	(164,149)	(19,736)
16																
17	Accumulated Amortization Beginning - CIAC	44,729	44,913	(184)	52,466	53,394	(928)	41,089	40,486	603	46,175	45,381	794	44,146	44,266	(120)
18	Adjustment - Opening Bal Adjt	8,098	8,481	(383)	(27,724)	(12,908)	(14,816)	5,089	4,895	194	(1,329)	(1,235)	(94)	2,916	2,486	430
19	Accumulated Amortization Ending - CIAC	36,631	53,394	(16,763)	24,742	40,486	(15,744)	46,178	45,381	797	44,846	44,146	700	47,062	46,752	310
20																
21	**Net Plant in Service, Mid-Year**	$ 2,318,274	$ 2,277,975	$ 40,299	$ 2,355,744	$ 2,310,134	$ 45,610	$ 2,417,393	$ 2,341,921	$ 75,472	$ 2,456,116	$ 2,383,478	$ 72,638	$ 2,441,849	$ 2,413,569	$ 28,280
22																
23	Adjustment to 13-Month Average		(1,745)	1,745		(2,663)	2,663		3,208	(3,208)		(2,057)	2,057	13,537	(2,157)	15,694
24	Work in Progress, No AFUDC	11,902	9,927	1,975	10,771	7,719	3,052	9,358	7,062	2,296	15,773	8,907	6,866	15,627	18,823	(3,196)
25	Unamortized Deferred Charges	13,110	9,424	3,686	(8,222)	(14,754)	6,532	(26,873)	(26,223)	(650)	(32,644)	(33,778)	1,134	(30,797)	(33,398)	2,601
26	Cash Working Capital	(29,050)	(21,611)	(7,439)	(25,197)	(23,624)	(1,573)	(28,452)	(25,044)	(3,408)	(33,754)	(26,908)	(6,846)	(7,553)	(5,226)	(2,327)
27	Gas In Storage Working Capital															
28	Other Working Capital (incl. Construction Advances)	194,350	171,058	23,292	143,971	152,220	(8,249)	136,185	176,112	(39,927)	138,198	134,924	3,274	103,439	135,255	(31,816)
29	Other															
30	Deferred Income Tax, mid-year	(364)	(364)	-	(606)	(609)	3	(604)	(609)	5	(552)	(609)	57			
31	LILO Benefit	(2,312)	(2,312)	-	(2,243)	(2,243)	-	(1,980)	(1,980)	-	(1,814)	(1,814)	-	(1,648)	(1,648)	-
32	Mid-Year Contributions															
33	**Utility Rate Base**	$ 2,505,910	$ 2,442,352	$ 63,558	$ 2,474,218	$ 2,426,180	$ 48,038	$ 2,505,027	$ 2,474,447	$ 30,580	$ 2,541,323	$ 2,462,143	$ 79,180	$ 2,534,454	$ 2,525,219	$ 9,236

FortisBC Energy (Vancouver Island) Inc
UTILITY RATE BASE
($000)

Line no.	Particulars	2006 Approved	2006 Actual	2006 Variance	2007 Approved	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved	2010 Actual	2010 Variance
1	Gas Plant in Service, Beginning	$ 643,193	$ 639,902	$ 3,291	$ 661,033	$ 661,033	$ -	$ 708,198	$ 708,198	$ -	$ 733,157	$ 733,157	$ -	$ 1,012,319	$ 1,007,359	$ 4,960
2	Adjustment - CPCNs / Opening Bal Adjt		4,819	(4,819)	1,759	1,759	-	3,624	1,989	1,635	208,237	208,237	-			
3	Gas Plant in Service, Ending	674,117	644,720	29,397	705,674	708,197	(2,523)	737,301	733,156	4,145	1,012,319	1,007,359	4,960	1,036,234	1,023,379	12,855
4																
7	Accumulated Depreciation Beginning - Plant	(136,943)	(138,807)	1,864	(152,817)	(152,817)	-	(161,749)	(161,749)	-	(178,029)	(178,025)	(4)	(245,154)	(244,628)	(526)
8	Adjustment - CPCNs / Opening Bal Adjt										(45,847)	(45,845)	(2)	(1,379)		(1,379)
9	Accumulated Depreciation Ending - Plant	(152,010)	(152,817)	807	(162,366)	(161,750)	(616)	(178,559)	(178,025)	(534)	(245,154)	(244,628)	(526)	(270,987)	(267,254)	(3,733)
10																
13	CIAC, Beginning										(60,835)	(60,835)	-	(278,861)	(278,712)	(149)
14	Adjustment - Opening Bal Adjt										(208,237)	(208,237)	-			-
15	CIAC, Ending										(278,861)	(278,712)	(149)	(275,728)	(275,876)	148
16																
19	Accumulated Amortization Beginning - CIAC										1,990	1,990	-	50,379	50,379	-
20	Adjustment - Opening Bal Adjt										45,847	45,845	2			-
21	Accumulated Amortization Ending - CIAC										50,380	50,380	-	54,795	54,799	(4)
22																
25	**Net Plant in Service, Mid-Year**	$ 514,179	$ 507,064	$ 7,114	$ 525,762	$ 528,212	$ (2,449)	$ 554,406	$ 551,784	$ 2,623	$ 517,483	$ 514,496	$ 2,987	$ 540,809	$ 534,723	$ 6,087
26																
27	Adjustment to 13-Month Average	1,212	1,178	34	(5,200)	(2,307)	(2,893)	818	893	(75)	6,489	6,216	273		(1,131)	1,131
28	Work in Progress, No AFUDC										3,652	1,691	1,961	3,608	2,280	1,328
29	Unamortized Deferred Charges										3,689		3,689	495	332	163
30	Cash Working Capital										(2,939)		(2,939)	(479)	1,029	(1,509)
31	Other Working Capital (incl. Construction Advances)	22,771	24,753	(1,982)	16,956	16,479	477	20,156	19,950	206	11,575	10,626	949	9,533	10,428	(896)
32	FEW - Allocated Net Income	(104)	(104)	-	(104)	(104)	-	(104)	(104)	-	(104)	(104)	-			
33	Mid-Year Contributions	(60,457)	(66,070)	5,612	(63,580)	(63,580)	-	(61,101)	(61,101)	-						
34	**Utility Rate Base**	$ 477,600	$ 466,822	$ 10,778	$ 474,714	$ 478,699	$ (3,985)	$ 514,175	$ 511,422	$ 2,753	$ 539,845	$ 532,925	$ 6,920	$ 553,966	$ 547,661	$ 6,305

FortisBC Energy (Whistler) Inc
UTILITY RATE BASE
($000)

Line			2006			2007			2008			2009			2010	
no.	Particulars	Approved[1]	Actual	Variance	Approved[2]	Actual	Variance	Approved[2]	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance
1	Gas Plant in Service, Beginning		$ 19,052		$ 19,538	$ 19,538	$ -	$ 19,668	$ 19,668	$ -	$ 20,110	$ 20,033	$ 77	$ 16,652	$ 16,159	$ 494
2	Adjustment - CPCNs / Opening Bal Adjt						-			-			-	(1,052)		(1,052)
3	Gas Plant in Service, Ending		19,538		19,668	19,668	-	20,033	20,033	-	22,446	16,159	6,287	16,056	16,594	(538)
4																
7	Accumulated Depreciation Beginning - Plant		(3,538)		(4,017)	(4,017)	-	(4,344)	(4,344)	-	(4,800)	(4,790)	(10)	1,323	1,402	(80)
8	Adjustment - CPCNs / Opening Bal Adjt													(4,462)		(4,462)
9	Accumulated Depreciation Ending - Plant		(4,017)		(4,344)	(4,344)	-	(4,790)	(4,790)	-	(5,241)	1,402	(6,643)	(3,323)	(3,168)	(155)
10																
13	CIAC, Beginning											(96)	96	(96)	(169)	74
14	Adjustment - Opening Bal Adjt															
15	CIAC, Ending											(169)	169	(96)	(186)	91
16																
19	Accumulated Amortization Beginning - CIAC											3	(3)	7	7	-
20	Adjustment - Opening Bal Adjt															
21	Accumulated Amortization Ending - CIAC											7	(7)	9	12	(3)
22																
25	**Net Plant in Service, Mid-Year**		$ 15,518		$ 15,423	$ 15,423	$ -	$ 15,283	$ 15,283	$ -	$ 16,258	$ 16,274	$ (16)	$ 12,509	$ 15,325	$ (2,816)
26																
27	Adjustment to 13-Month Average															
28	Work in Progress, No AFUDC										9	-	9	63	18	45
29	Unamortized Deferred Charges										21,352	-	21,352	29,363	29,440	(77)
30	Cash Working Capital										(84)	-	(84)	47	7	40
31	Other Working Capital (incl. Construction Advances)		1,417		1,304	1,304	-	1,395	1,395	-	1,176	15,140	(13,963)	586	610	(24)
32	FEVI - Allocated Net Income		104		104	104	-	104	104	-	104	104	-			
33	Mid-Year Contributions															
34	**Utility Rate Base**		$ 17,040		$ 16,831	$ 16,831	$ -	$ 16,782	$ 16,782	$ -	$ 38,816	$ 31,518	$ 7,298	$ 42,568	$ 45,400	$ (2,832)

Notes:
1) No Approved numbers for 2006
2) 2007 and 2008 are not test years. FEW had a ROE deferral account that allowed it to earn its regulated return from its last test year in 2005

Fort Nelson
UTILITY RATE BASE
($000)

Line no.	Particulars	2006 Approved[1]	2006 Actual	2006 Variance	2007 Approved[1]	2007 Actual	2007 Variance	2008 Approved	2008 Actual	2008 Variance	2009 Approved	2009 Actual	2009 Variance	2010 Approved[1]	2010 Actual	2010 Variance
1	Gas Plant in Service, Beginning		$ 7,143			$ 7,540		$ 7,701	$ 7,672	$ 29	$ 7,965	$ 7,865	$ 100		$ 8,146	
2	Adjustment - CPCNs / Opening Bal Adjt		396			132		213	(20)	233	334	281	53		495	
3	Gas Plant in Service, Ending		7,540			7,672		7,913	7,865	48	8,300	8,146	154		8,641	
4																
5	Accumulated Depreciation Beginning - Plant		(1,690)			(1,783)		(1,810)	(1,865)	55	(2,064)	(2,021)	(43)		(2,033)	
6	Adjustment - CPCNs / Opening Bal Adjt															
7	Accumulated Depreciation Ending - Plant		(1,787)			(1,865)		(2,010)	(2,021)	11	(2,271)	(2,033)	(238)		(2,214)	
8																
9	CIAC, Beginning		(1,041)			(1,159)		(1,200)	(1,159)	(41)	(1,159)	(1,179)	20		(1,271)	
10	Adjustment - Opening Bal Adjt															
11	CIAC, Ending		(1,041)			(1,159)		(1,200)	(1,179)	(21)	(1,159)	(1,271)	112		(1,287)	
12																
13	Accumulated Amortization Beginning - CIAC		472			509		550	543	7	554	429	125		452	
14	Adjustment - Opening Bal Adjt															
15	Accumulated Amortization Ending - CIAC		509			543		591	429	162	576	452	124		490	
16																
19	**Net Plant in Service, Mid-Year**		$ 5,103			$ 5,209		$ 5,272	$ 5,142	$ 130	$ 5,371	$ 5,194	$ 177		$ 5,462	
20																
21	Adjustment to 13-Month Average		(25)			8			(18)	18		(84)	84		(95)	
22	Work in Progress, No AFUDC		6			25			55	(55)		143	(143)		235	
23	Unamortized Deferred Charges		(29)			2		85	157	(72)	307	79	228		64	
24	Cash Working Capital		(215)			(213)		(221)	(252)	31	(277)	(290)	13		(273)	
25	Other Working Capital (incl. Construction Advances)		18			17		18	9	9	3	13	(10)		17	
26	Mid-Year Contributions															
27	**Utility Rate Base**		$ 4,858			$ 5,048		$ 5,154	$ 5,093	$ 61	$ 5,405	$ 5,055	$ 350		$ 5,410	

Notes:
1) No Approved numbers for 2006, 2007, 2010

Appendix D-6

CAPEX HISTORIC AMALGAMATION

FORTISBC ENERGY INC. (COMBINED)
BASE CAPITAL EXPENDITURES ($000's)
FOR THE YEARS ENDING DECEMBER 31

		2006	2007	2008	2009	2010
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 12,233	$ 10,842	$ 12,153	$ 15,409	$ 20,307
3	Transmission System Reinforcements/Integrity and Reliability	13,788	10,612	18,486	17,304	13,607
4	Distribution System Reinforcements/Integrity and Reliability	10,444	14,618	9,247	9,723	6,573
5	Distribution Mains and Service Renewals and Alterations	13,406	11,016	11,559	14,501	12,542
6	**Total Sustainment Capital**	49,871	47,088	51,446	56,937	53,029
7						
8	**Growth Capital**					
9	New Customer Mains	11,600	12,342	17,111	8,823	6,616
10	New Customer Services	21,874	23,338	25,223	18,050	19,337
11	New Customer Meters	4,863	4,819	4,103	2,124	2,348
12	**Total Growth Capital**	38,337	40,500	46,437	28,997	28,301
13						
14	**Other**					
15	Equipment	3,276	2,377	3,174	8,035	4,620
16	Facilities	2,223	4,156	2,490	3,486	4,592
17	IT	9,494	4,579	11,835	16,034	13,891
18	Ft Nelson	-	-	-	-	-
19	**Total Other**	14,992	11,111	17,499	27,555	23,103
20						
21		$ 103,200	$ 98,699	$ 115,382	$ 113,489	$ 104,433

FORTISBC ENERGY INC. (COMBINED)
2006 BASE CAPITAL EXPENDITURES ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 11,920	$ 304	$ 9		$ 12,233
3	Transmission System Reinforcements/Integrity and Reliability	8,663	5,125			13,788
4	Distribution System Reinforcements/Integrity and Reliability	9,705	739	-		10,444
5	Distribution Mains and Service Renewals and Alterations	11,982	1,369	55		13,406
6	**Total Sustainment Capital**	42,270	7,537	64	-	49,871
7						
8	**Growth Capital**					
9	New Customer Mains	8,147	3,399	54		11,600
10	New Customer Services	16,404	5,427	43		21,874
11	New Customer Meters	4,269	580	14		4,863
12	**Total Growth Capital**	28,820	9,406	111	-	38,337
13						
14	**Other**					
15	Equipment	3,104	172	-		3,276
16	Facilities	2,061	162	-		2,223
17	IT	7,835	1,659			9,494
18	Ft Nelson	(499)			499	-
19	**Total Other**	12,501	1,992	-	499	14,992
20						
21		$ 83,591	$ 18,936	$ 175	$ 499	$ 103,200

FORTISBC ENERGY INC. (COMBINED)
2007 BASE CAPITAL EXPENDITURES ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 9,967	$ 851	$ 24		$ 10,842
3	Transmission System Reinforcements/Integrity and Reliability	5,096	5,516			10,612
4	Distribution System Reinforcements/Integrity and Reliability	10,353	4,265	-		14,618
5	Distribution Mains and Service Renewals and Alterations	9,309	1,692	15		11,016
6	**Total Sustainment Capital**	34,725	12,324	39	-	47,088
7						
8	**Growth Capital**					
9	New Customer Mains	8,106	4,201	35		12,342
10	New Customer Services	17,079	6,172	87		23,338
11	New Customer Meters	3,720	1,063	37		4,819
12	**Total Growth Capital**	28,905	11,436	159	-	40,500
13						
14	**Other**					
15	Equipment	2,356	20	1		2,377
16	Facilities	3,163	993	-		4,156
17	IT	4,171	408			4,579
18	Ft Nelson	(162)			162	-
19	**Total Other**	9,528	1,420	1	162	11,111
20						
21		$ 73,158	$ 25,180	$ 199	$ 162	$ 98,699

FORTISBC ENERGY INC. (COMBINED)
2008 BASE CAPITAL EXPENDITURES ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 11,563	$ 567	$ 23		$ 12,153
3	Transmission System Reinforcements/Integrity and Reliability	13,308	5,178			18,486
4	Distribution System Reinforcements/Integrity and Reliability	8,136	1,111	-		9,247
5	Distribution Mains and Service Renewals and Alterations	9,400	2,065	94		11,559
6	**Total Sustainment Capital**	42,407	8,922	117	-	51,446
7						
8	**Growth Capital**					
9	New Customer Mains	10,991	5,915	205		17,111
10	New Customer Services	17,984	7,072	167		25,223
11	New Customer Meters	3,314	754	35		4,103
12	**Total Growth Capital**	32,289	13,741	407	-	46,437
13						
14	**Other**					
15	Equipment	2,996	121	57		3,174
16	Facilities	1,988	502	-		2,490
17	IT	10,468	1,367			11,835
18	Ft Nelson	(150)			150	-
19	**Total Other**	15,302	1,990	57	150	17,499
20						
21		$ 89,998	$ 24,653	$ 581	$ 150	$ 115,382

FORTISBC ENERGY INC. (COMBINED)
2009 BASE CAPITAL EXPENDITURES ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 14,479	$ 907	$ 23		$ 15,409
3	Transmission System Reinforcements/Integrity and Reliability	12,022	5,282			17,304
4	Distribution System Reinforcements/Integrity and Reliability	8,592	1,131	-		9,723
5	Distribution Mains and Service Renewals and Alterations	12,759	1,423	319		14,501
6	**Total Sustainment Capital**	47,852	8,743	342	-	56,937
7						
8	**Growth Capital**					
9	New Customer Mains	6,140	2,586	97		8,823
10	New Customer Services	12,094	5,742	214		18,050
11	New Customer Meters	1,503	588	33		2,124
12	**Total Growth Capital**	19,737	8,916	344	-	28,997
13						
14	**Other**					
15	Equipment	6,640	1,335	60		8,035
16	Facilities	2,805	681	-		3,486
17	IT	14,245	1,789			16,034
18	Ft Nelson	(311)			311	-
19	**Total Other**	23,379	3,805	60	311	27,555
20						
21		$ 90,968	$ 21,464	$ 746	$ 311	$ 113,489

FORTISBC ENERGY INC. (COMBINED)
2010 BASE CAPITAL EXPENDITURES ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	**Sustainment Capital**					
2	Meter Recalls/Exchanges	$ 19,129	$ 1,134	$ 44		$ 20,307
3	Transmission System Reinforcements/Integrity and Reliability	9,771	3,836	-		13,607
4	Distribution System Reinforcements/Integrity and Reliability	5,537	991	45		6,573
5	Distribution Mains and Service Renewals and Alterations	11,359	1,156	27		12,542
6	**Total Sustainment Capital**	45,796	7,117	116	-	53,029
7						
8	**Growth Capital**					
9	New Customer Mains	4,561	1,836	219		6,616
10	New Customer Services	13,906	5,309	122		19,337
11	New Customer Meters	1,915	430	3		2,348
12	**Total Growth Capital**	20,382	7,575	344	-	28,301
13						
14	**Other**					
15	Equipment	3,434	1,181	5		4,620
16	Facilities	4,177	400	15		4,592
17	IT	12,418	1,473			13,891
18	Ft Nelson	(424)			424	-
19	**Total Other**	19,605	3,054	20	424	23,103
20						
21		$ 85,783	$ 17,746	$ 480	$ 424	$ 104,433

FORTISBC ENERGY INC. (COMBINED)
CAPEX TO ADDITIONS ($000's)
FOR THE YEARS ENDING DECEMBER 31

Line		2006	2007	2008	2009	2010
1	CPCN's					
2	Opening Work in Progress	$ 8,631	$ 7,128	$ 31,756	$ 99,554	$ 128,405
3	Add - Capital Expenditures- CPCNs	8,809	46,070	75,645	88,833	99,027
4	Less - Closing Work in Progress	(7,128)	(31,756)	(99,554)	(128,405)	(227,229)
5	Total Plant Additions - CPCNs	$ 10,312	$ 21,441	$ 7,848	$ 59,982	$ 203
6						
7	Non-CPCNs					
8	Opening Work in Progress	$ 19,405	$ 28,145	$ 15,790	$ 25,704	$ 29,939
9	Add - Capital Expenditures- Non-CPCNs	103,200	98,699	115,382	113,489	104,433
10	Add- Adjustments	4,036	4,163	544	(2,840)	8,258
11	Less - Closing Work in Progress	(28,145)	(15,790)	(25,704)	(29,939)	(38,957)
12	Non-CPCN Additions to Gas Plant in Service	98,496	115,217	106,012	106,414	103,673
13						
14	Less: Opening WIP Adjustment	(2)	-	-	-	-
15	Add: O&M Charged To Construction	32,034	32,559	32,647	33,434	33,510
16						
17	Total Plant Additions- Non-CPCNs	$ 130,528	$ 147,776	$ 138,659	$ 139,848	$ 137,183

FORTISBC ENERGY INC. (COMBINED)
2006 CAPEX TO ADDITIONS ($000's)

	Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
CPCN's					
Opening Work in Progress	$ 4,336	$ 4,295			$ 8,631
Add - Capital Expenditures- CPCNs [1]	2,541	6,106	162		8,809
Less - Closing Work in Progress	(2,541)	(4,587)			(7,128)
Total Plant Additions - CPCNs	$ 4,336	$ 5,814	$ 162	$ -	$ 10,312
Non-CPCNs					
Opening Work in Progress	$ 15,830	$ 3,575	$ -		$ 19,405
Add - Capital Expenditures- Non-CPCNs	83,591	18,936	175	499	103,200
Add- Adjustments [2]	1,613	2,525	(9)	(94)	4,036
Less - Closing Work in Progress	(15,611)	(12,525)	(9)		(28,145)
Non-CPCN Additions to Gas Plant in Service	85,423	12,511	157	405	98,496
Less: Opening WIP Adjustment	(2)				(2)
Add: O&M Charged To Construction	27,111	4,627	164	132	32,034
Total Plant Additions- Non-CPCNs	$ 112,532	$ 17,138	$ 321	$ 537	$ 130,528

[1] Includes AFUDC on CPCN's

[2] Adjustments related to AFUDC, CIAC and removal costs

FORTISBC ENERGY INC. (COMBINED)
2007 CAPEX TO ADDITIONS ($000's)

		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	CPCN's					
2	Opening Work in Progress	$ 2,541	$ 4,587	$ -	$ -	$ 7,128
3	Add - Capital Expenditures- CPCNs [1]	18,661	27,409		-	46,070
4	Less - Closing Work in Progress	(10,355)	(21,401)		-	(31,756)
5	Total Plant Additions - CPCNs	$ 10,846	$ 10,595	$ -	$ -	$ 21,441
6						
7	Non-CPCNs					
8	Opening Work in Progress	$ 15,611	$ 12,525	$ 9	$ -	$ 28,145
9	Add - Capital Expenditures- Non-CPCNs	73,158	25,180	199	162	98,699
10	Add- Adjustments [2]	1,241	2,981	13	(72)	4,163
11	Less - Closing Work in Progress	(12,721)	(2,950)	(119)		(15,790)
12	Non-CPCN Additions to Gas Plant in Service	77,289	37,736	102	90	115,217
13						
14	Less: Opening WIP Adjustment	-	-	-	-	-
15	Add: O&M Charged To Construction	27,399	4,859	165	136	32,559
16						
17	Total Plant Additions- Non-CPCNs	$ 104,688	$ 42,595	$ 267	$ 226	$ 147,776
18						

19 [1] Includes AFUDC on CPCN's
20 [2] Adjustments related to AFUDC, CIAC and removal costs

FORTISBC ENERGY INC. (COMBINED)
2008 CAPEX TO ADDITIONS ($000's)

	Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
CPCN's					
Opening Work in Progress	$ 10,355	$ 21,401	$ -	$ -	$ 31,756
Add - Capital Expenditures- CPCNs [1]	12,168	63,477		-	75,645
Less - Closing Work in Progress	(14,676)	(84,878)		-	(99,554)
Total Plant Additions - CPCNs	$ 7,848	$ -	$ -	$ -	$ 7,848
Non-CPCNs					
Opening Work in Progress	$ 12,721	$ 2,950	$ 119	$ -	$ 15,790
Add - Capital Expenditures- Non-CPCNs	89,998	24,653	581	150	115,382
Add- Adjustments [2]	86	295	216	(53)	544
Less - Closing Work in Progress	(18,760)	(6,307)	(637)		(25,704)
Non-CPCN Additions to Gas Plant in Service	84,045	21,591	279	97	106,012
Less: Opening WIP Adjustment	-	-	-	-	-
Add: O&M Charged To Construction	27,543	4,865	98	141	32,647
Total Plant Additions- Non-CPCNs	$ 111,588	$ 26,456	$ 377	$ 238	$ 138,659

[1] Includes AFUDC on CPCN's

[2] Adjustments related to AFUDC, CIAC and removal costs

FORTISBC ENERGY INC. (COMBINED)
2009 CAPEX TO ADDITIONS ($000's)

Line		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	CPCN's					
2	Opening Work in Progress	$ 14,676	$ 84,878	$ -	$ -	$ 99,554
3	Add - Capital Expenditures- CPCNs [1]	8,858	78,288	1,687	-	88,833
4	Less - Closing Work in Progress	(10,655)	(117,750)	-	-	(128,405)
5	Total Plant Additions - CPCNs	$ 12,879	$ 45,416	$ 1,687	$ -	$ 59,982
6						
7	Non-CPCNs					
8	Opening Work in Progress	$ 18,760	$ 6,307	$ 637	$ -	$ 25,704
9	Add - Capital Expenditures- Non-CPCNs	90,968	21,464	746	311	113,489
10	Add- Adjustments [2]	673	(3,628)	114	1	(2,840)
11	Less - Closing Work in Progress	(23,520)	(6,275)	(144)		(29,939)
12	Non-CPCN Additions to Gas Plant in Service	86,881	17,868	1,353	312	106,414
13						
14	Less: Opening WIP Adjustment	-	-	-	-	-
15	Add: O&M Charged To Construction	28,113	5,032	163	126	33,434
16						
17	Total Plant Additions- Non-CPCNs	$ 114,994	$ 22,900	$ 1,516	$ 438	$ 139,848
18						

19 [1] Includes AFUDC on CPCN's and incorrect overhead allocation from non-CPCNs in FEVI 2009 annual report

20 [2] Mainly AFUDC for FEU and incorrect overhead allocation to CPCN's in FEVI 2009 annual report

FORTISBC ENERGY INC. (COMBINED)
2010 CAPEX TO ADDITIONS ($000's)

Line		Mainland	Vancouver Island	Whistler	Ft Nelson	Combined
1	CPCN's					
2	Opening Work in Progress	$ 10,655	$ 117,750	$ -	$ -	$ 128,405
3	Add - Capital Expenditures- CPCNs [1]	37,579	61,357	91		99,027
4	Less - Closing Work in Progress	(48,031)	(179,107)	(91)		(227,229)
5	Total Plant Additions - CPCNs	$ 203	$ -	$ -	$ -	$ 203
6						
7	Non-CPCNs					
8	Opening Work in Progress	$ 23,520	$ 6,275	$ 144	$ -	$ 29,939
9	Add - Capital Expenditures- Non-CPCNs	85,783	17,746	480	424	104,433
10	Add- Adjustments [2]	7,331	880	(71)	118	8,258
11	Less - Closing Work in Progress	(30,007)	(8,934)	(16)		(38,957)
12	Non-CPCN Additions to Gas Plant in Service	86,627	15,967	537	542	103,673
13						
14	Less: Opening WIP Adjustment	-				-
15	Add: O&M Charged To Construction	28,905	4,372	119	114	33,510
16						
17	Total Plant Additions- Non-CPCNs	$ 115,532	$ 20,339	$ 656	$ 656	$ 137,183
18						

19 [1] Includes AFUDC on CPCN's

20 [2] Mainly AFUDC for FEU and Capital Vehicle Lease for FEI

Appendix D-7

CUSTOMER SERVICE CALL VOLUME DATA FOR 2008-2010

Customer Service Department
Contact Centre Data
Actual Call Volumes for 2008 to 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2008													
Billing	77,531	87,653	71,532	78,841	69,255	63,818	64,590	59,977	68,079	73,419	56,050	51,799	**822,544**
Collections Inbound	18,224	26,874	24,135	29,377	22,898	21,860	17,245	14,028	13,651	12,527	10,187	9,142	**220,148**
Emergency	6,959	7,005	6,289	6,345	5,901	6,055	5,740	5,080	5,891	6,770	5,886	7,289	**75,210**
Collections Outbound	5,974	4,687	2,100	3,806	7,421	4,783	4,141	3,174	2,285	1,244	1,418	2,284	**43,317**
2008 Total	**108,688**	**126,219**	**104,056**	**118,369**	**105,475**	**96,516**	**91,716**	**82,259**	**89,906**	**93,960**	**73,541**	**70,514**	**1,161,219**
2009													
Billing	69,920	58,429	65,740	60,694	57,675	61,346	57,703	55,661	61,324	64,166	56,836	50,692	**720,186**
Collections	10,978	12,822	17,881	22,306	21,071	22,317	15,039	12,585	12,582	13,015	10,644	10,169	**181,409**
Emergency	6,499	5,149	5,647	6,364	5,947	6,221	4,958	5,092	5,424	6,799	6,001	6,260	**70,361**
Collections Outbound	1,920	2,904	3,079	5,045	4,953	4,708	3,910	2,907	2,892	2,695	2,339	3,260	**40,612**
2009 Total	**89,317**	**79,304**	**92,347**	**94,409**	**89,646**	**94,592**	**81,610**	**76,245**	**82,222**	**86,675**	**75,820**	**70,381**	**1,012,568**
2010													
Billing	56,332	50,038	60,551	53,348	50,755	53,099	49,726	48,858	49,870	50,269	53,839	44,832	**621,517**
Collections	15,923	17,341	19,762	15,558	16,104	15,338	12,885	11,478	11,402	11,003	11,530	11,271	**169,595**
Emergency	5,492	4,937	5,242	4,859	4,824	4,518	4,793	4,514	4,955	5,906	6,833	6,344	**63,217**
Collections Outbound	4,544	4,947	4,593	3,496	3,186	2,416	2,200	2,050	2,164	1,793	1,435	1,998	**34,822**
2010 Total	**82,291**	**77,263**	**90,148**	**77,261**	**74,869**	**75,371**	**69,604**	**66,900**	**68,391**	**68,971**	**73,637**	**64,445**	**889,151**
3 Year Average	**93,432**	**94,262**	**95,517**	**96,680**	**89,997**	**88,826**	**80,977**	**75,135**	**80,173**	**83,202**	**74,333**	**68,447**	**1,020,979**

This call volume data is the information derived from the Peace data system and represents data entered by Accenture's (current outsourced provider) customer service representatives.

The 2009 call volumes were used to estimate staffing numbers, as this call volume was close to the average for 2008 to 2010 three year period.

Notes

Billing Calls refer to general customer service account inquiries including requests for account balances, payment information, processing of payments, and meter read investigation

Emergency calls refer to inbound calls from customers advising of a potential gas leak in their home environment, details are documented and a technician is immediately dispatched to investigate

Outbound collection calls refer to calls to customers who have been delinquent in payment on their outstanding account balance.

Inbound collections are calls received from customers who have been delinquent on their payment of their outstanding account balance and are looking to resolve the issue or to make payment arrangements. In addition, inbound calls include calls from customers with whom we have left a voice message in reference to their account.

Appendix E-1

GANNETT FLEMING DEPRECIATION REPORT

FORTISBC ENERGY INC.

Surrey, British Columbia

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS AT DECEMBER 31, 2009

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania | Calgary, Alberta | Valley Forge, Pennsylvania

GANNETT FLEMING, INC.
Suite 277
200 Rivercrest Drive S.E.
Calgary, Alberta T2C 2X5

Office: (403) 257-5946
Fax: (403) 257-5947
www.gannettfleming.com

April 18, 2011

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, British Columbia V4N 0E8

Attention: Mr. James Wong
Director, Finance and Planning

Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas plant of FortisBC Energy Inc. at December 31, 2009. The depreciation study has developed depreciation rates for the Mainland, Vancouver Island, and Whistler systems. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and net salvage, and the summary and detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of FortisBC Energy Inc. personnel in the completion of the study.

Respectfully submitted,

GANNETT FLEMING INC.

LARRY E. KENNEDY
Director, Canadian Services
Valuation and Rate Division

LEK/hac
Project: 052733

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PART I. INTRODUCTION

FORTISBC ENERGY INC.
DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT DECEMBER 31, 2009

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted by Gannett Fleming, Inc. ("Gannett Fleming") for FortisBC Energy Inc. (FortisBC) to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes applicable to the original cost of gas plant at December 31, 2009. Separate annual accrual rates have been developed for the provision applicable to the average service life and net salvage components of depreciation expense for each of the FortisBC Energy Inc., FortisBC Energy Inc. (Vancouver Island) Inc., and FortisBC (Whistler) Inc. systems.

The depreciation accrual rates presented herein are based on generally-accepted methods and procedures for calculating depreciation. The service life estimates were based on analyses incorporating data through December 31, 2009, a review of Company practices and outlook as they relate to plant operation and retirement, and the service life and net salvage estimates for other gas transmission and distribution companies.

Part I, Introduction, of this report, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and net salvage, and in the calculation of depreciation. Part III, Results of Study, presents a summary of annual and accrued depreciation. Part lV, Service Life Statistics presents the statistical analyses of service life. Part V, Net Salvage Statistics presents the annual, 3 year moving average and the most recent 5 year moving average, statistical analysis of historic net salvage transactions. Part VI, Detailed Depreciation Calculations presents the detailed tabulations of annual and accrued depreciation.

BASIS OF THE STUDY

Depreciation. The annual and accrued depreciation were calculated by the straight line method using the average service life procedure and applied on a remaining life basis. The calculations of composite remaining life and annual depreciation accrual amounts were based on attained ages and estimated service life and net salvage characteristics for each depreciable group of assets.

Service Life and Net Salvage Estimates. The method of estimating service lives consisted of compiling the service life history of the plant accounts and subaccounts, reducing this history to trends through the use of Retirement Rate Method of analysis as further described in Part III of this report, and then applying judgment to make a final estimate of average service life. The results of the statistical analysis resulted in the forecasting of the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The service life estimates used in the depreciation calculations incorporated historical data compiled from the property records of the Company. Such data included plant additions, retirements, transfers and other activity from 1958 through 2009. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement were obtained through discussions with operating and management personnel, and through a your of company facilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves. The estimates of net salvage were based on judgment which incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of the gas utility industry, and comparison of the net salvage estimates from studies of other gas utilities. The estimates of net salvage are expressed as the average net percent of the investment to be incurred or recovered upon its retirement. In order to comply with announcements from the Canadian Accounting Standards Board relating to the implementation of the International Financial Reporting Standards ("IFRS"), FortisBC has asked Gannett Fleming to develop separate annual accrual and accumulated depreciation calculations related to the requirements for net salvage. A summary of the calculations relating specifically to the net salvage requirement is presented in the Results section of this report.

RECOMMENDATIONS

The calculated annual depreciation accrual rates set forth herein apply specifically to gas plant as of December 31, 2009. Continued surveillance and periodic revisions are required to maintain use of appropriate depreciation rates. The survivor curves, amortization periods and net salvage percents determined in this study should be the basis for periodic recalculations. Complete depreciation studies which re-evaluate these parameters should be performed every three to five years.

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Service Value, in public utility regulation, means the difference between original cost and the net salvage value of gas plant.[1] Net Salvage Value is considered to be the amount received for property retired less any expenses incurred in connection with the sale of the asset, or in preparing the asset for sale.[2] As such, the depreciation study completed by Gannett Fleming and as presented in this report has developed annual accrual rates applicable to both the recovery of the original costs and separately for the net salvage component of the utility assets in service as at December 31, 2009.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders

[1]Federal Energy Regulatory Commission, Natural Gas Act, Part 201-Uniform System of Accounts Prescribed for Natural Gas Companies subject to the Provisions of the Natural Gas Act, Page 516-Definitions.

[2] Ibid, footnote 1

service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual depreciation based on the straight line method requires the estimation of average life and salvage and the selection of group depreciation procedures. These subjects are discussed in the sections that follow.

ESTIMATION OF SURVIVOR CURVES

Average Service Life The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

Survivor Curves The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

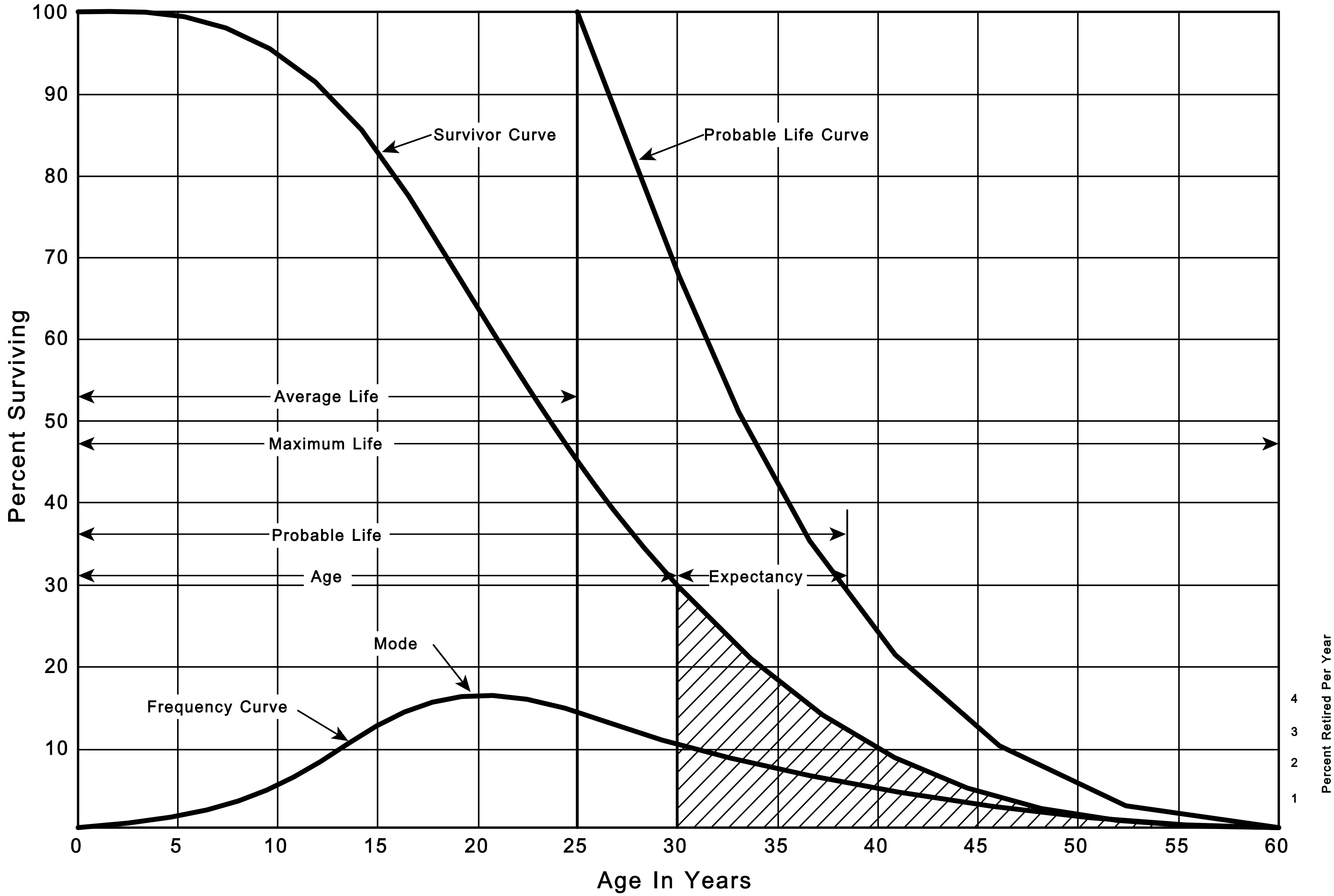

Figure 1. A Typical Survivor Curve and Derived Curves

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[3] These type curves have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[4] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[5] presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis. The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging un-aged amounts and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[6] "Engineering Valuation and Depreciation,"[7] and "Depreciation Systems."[8]

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3 Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

4 Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

5 Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

6 Winfrey, Robley, Supra Note 1.

7 Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

8 Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press.1994

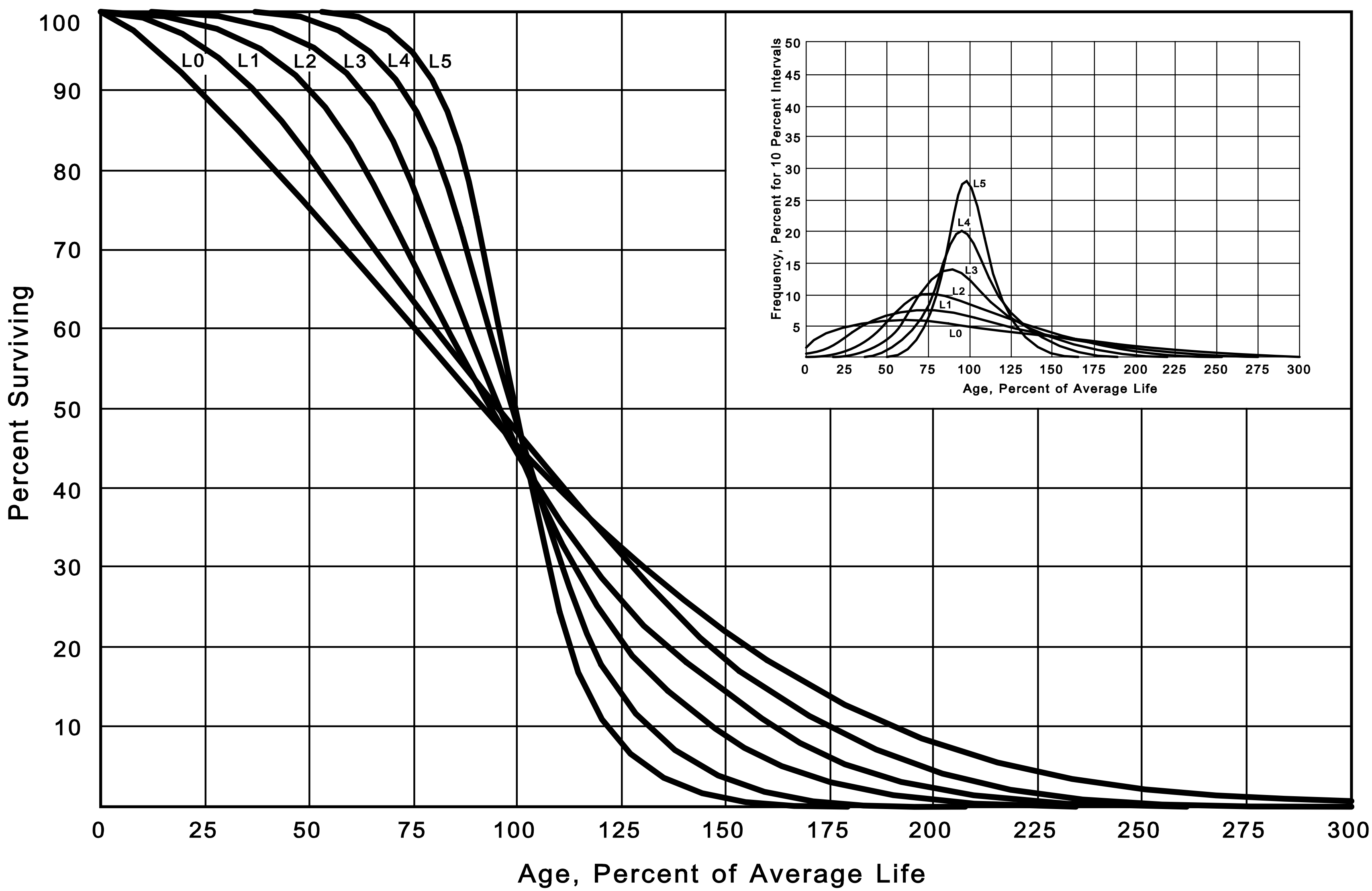


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

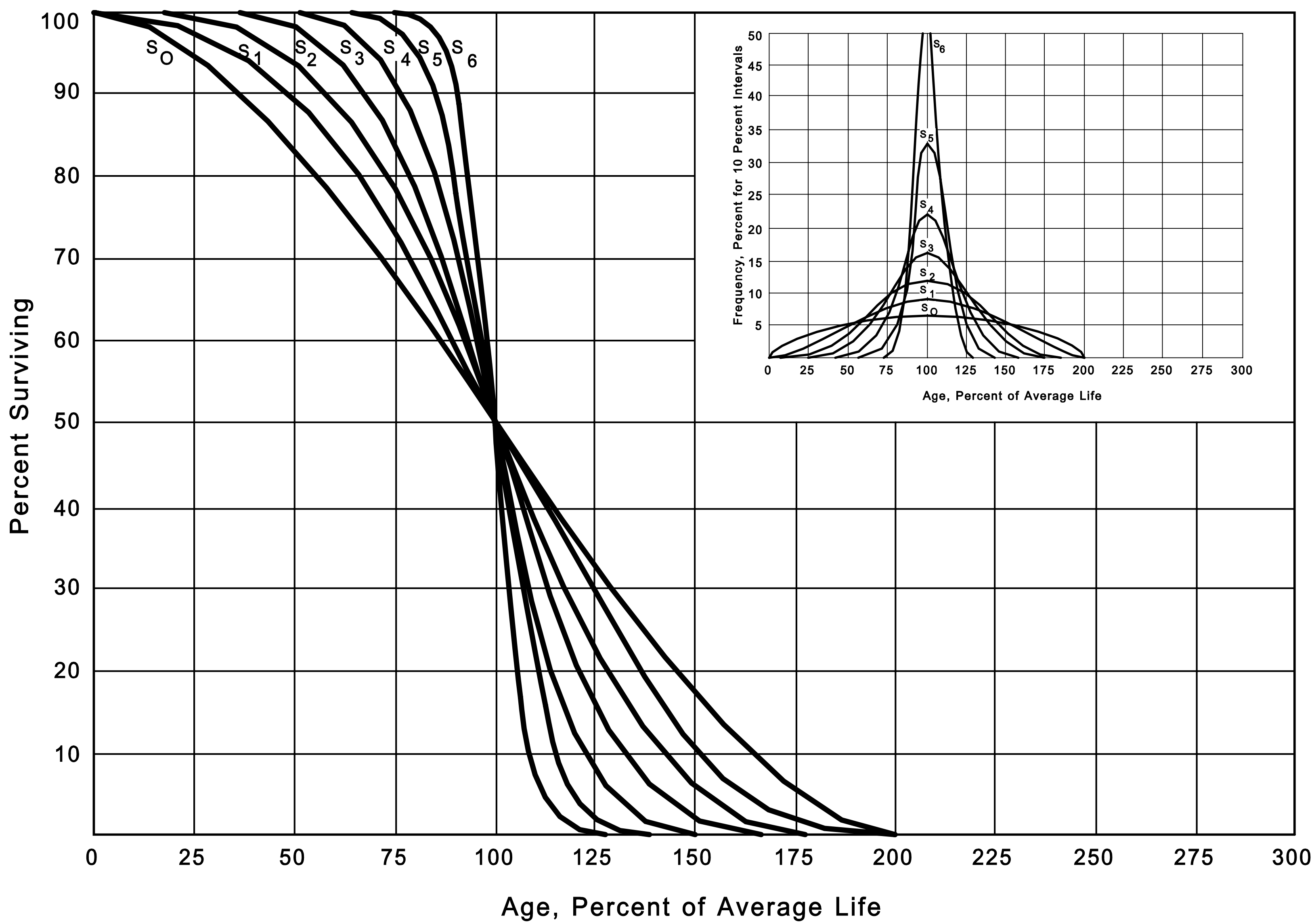


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

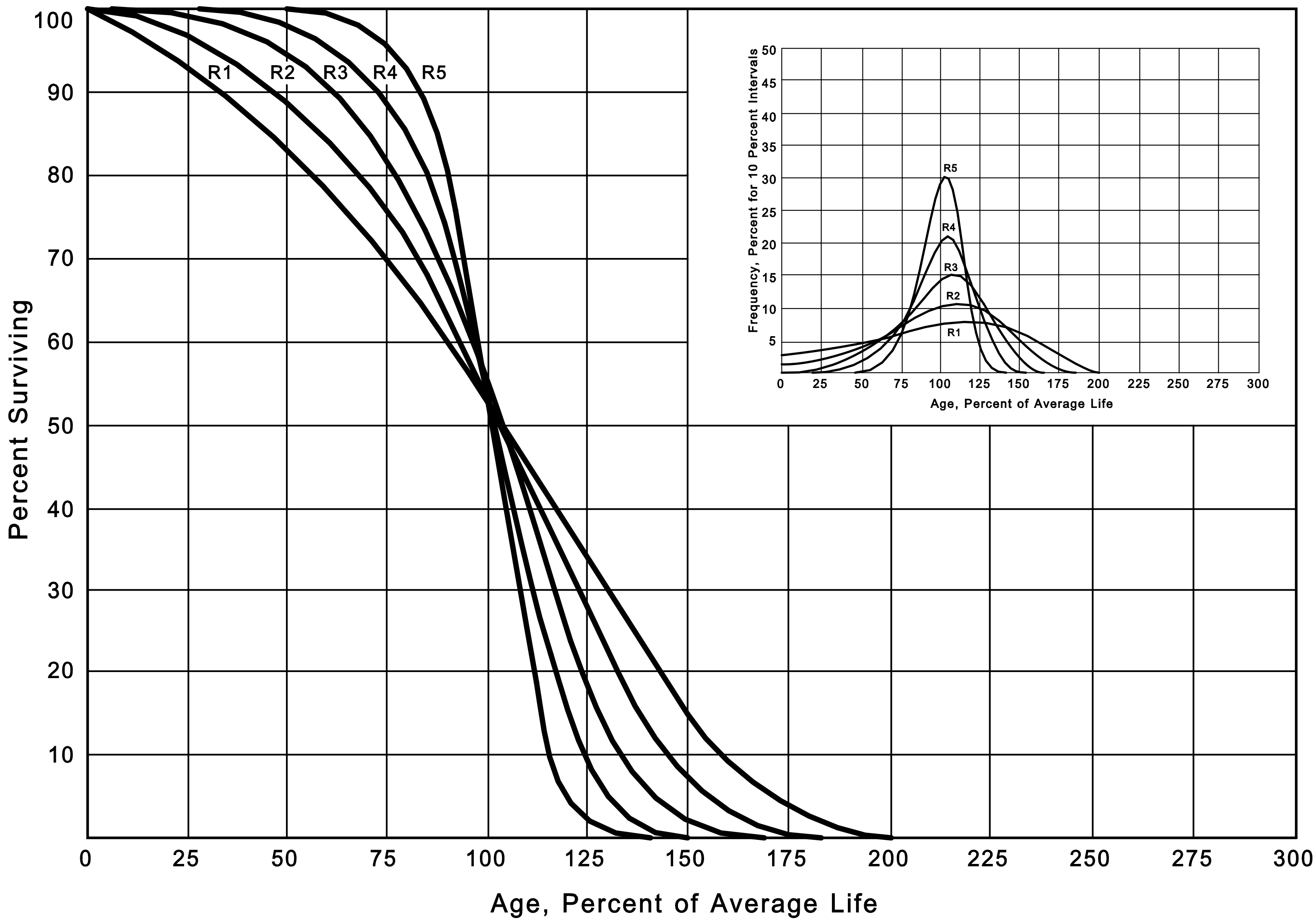


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

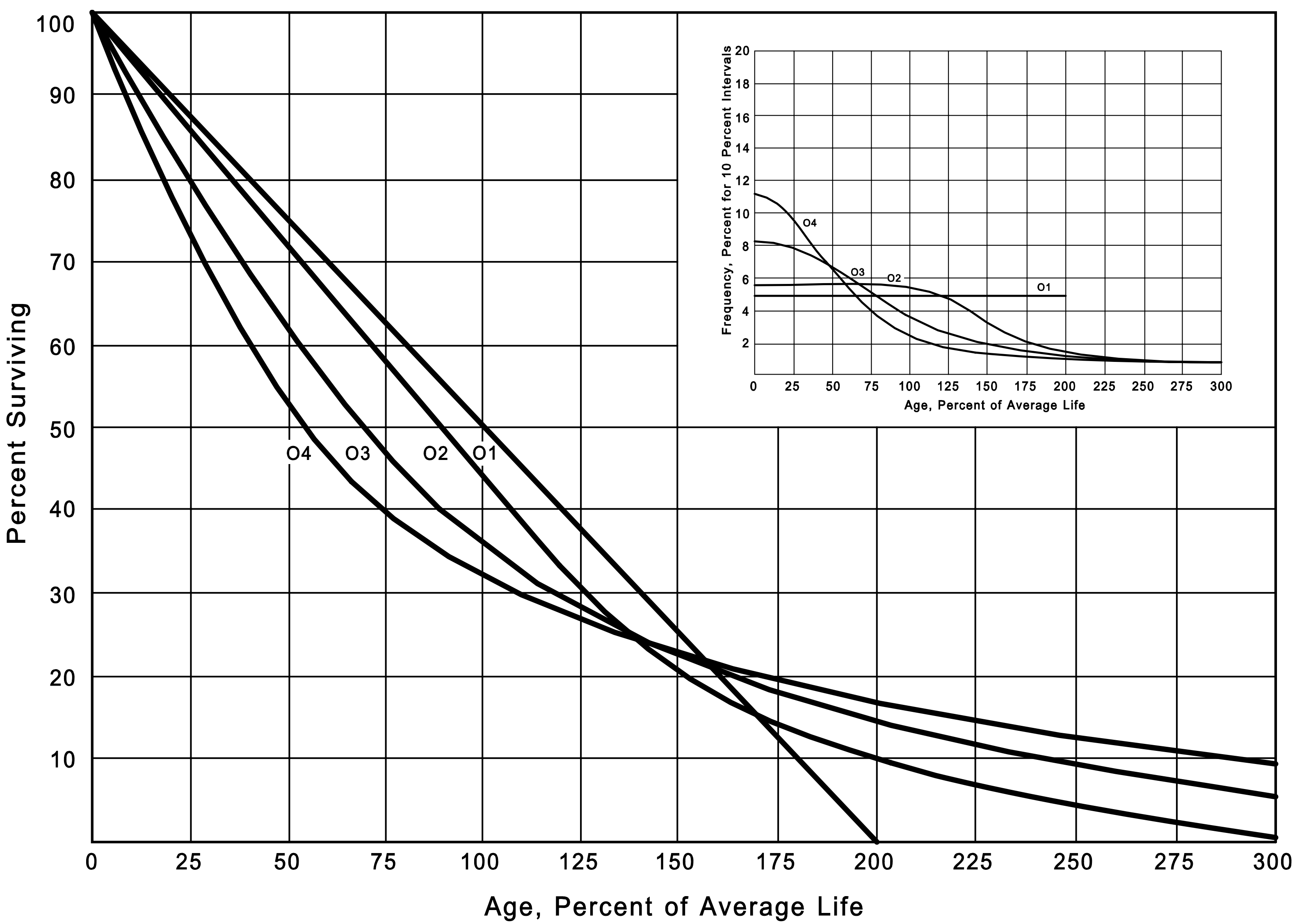


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginnings of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records The property group used to illustrate the retirement rate method is observed for the experience band 2000-2009 during which there were placements during the years 1995-2009. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on the following pages. In Table 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 1995 were retired in 2000. The \$10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of

TABLE 1. RETIREMENTS FOR EACH YEAR 2000-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2000-2009 — Placement Band 1995-2009

Year Placed	Retirements, Thousands of Dollars During Year 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1995	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1996	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1997	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1998	8	9	10	11	11	13	14	15	16	17	83	10½-11½
1999	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2000	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2001		5	11	12	13	14	15	16	18	20	113	7½-8½
2002			6	12	13	15	16	17	19	19	124	6½-7½
2003				6	13	15	16	17	19	19	131	5½-6½
2004					7	14	16	17	19	20	143	4½-5½
2005						8	18	20	22	23	146	3½-4½
2006							9	20	22	25	150	2½-3½
2007								11	23	25	151	1½-2½
2008									11	24	153	½-1½
2009										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 2000-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2000-2009 | Placement Band 1995-2009

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Placed (1)	2000 (2)	2001 (3)	2002 (4)	2003 (5)	2004 (6)	2005 (7)	2006 (8)	2007 (9)	2008 (10)	2009 (11)	Total During Age Interval (12)	Age Interval (13)
1995	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
1996	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1997	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1998	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
1999	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2000		-	-	-	-	-	-	-	-	-	(5)	8½-9½
2001			-	-	-	-	-	-	-	-	-	7½-8½
2002			-	-	-	-	-	-	-	-	-	6½-7½
2003				-	-	-	-	(12)[b]	-	-	-	5½-6½
2004					-	-	-	-	22[a]	-	-	4½-5½
2005						-	-	(19)[b]	-	-	10	3½-4½
2006							-	-	-	-	-	2½-3½
2007								-	-	(102)[c]	(121)	1½-2½
2008									-	-	-	½-1½
2009											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount

time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Table 1 immediately above the stairstep line drawn on the table beginning with the 2000 retirements of 1995 installations and ending with the 2009 retirements of the 2004 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Table 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement. The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Table 3 on page II-16. The surviving plant at the beginning of each year from 2000 through 2009 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Tables 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2005 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2000-2009, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown in Table 3 as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table. The original life table, illustrated in Table 4 on page II-17, is developed from the totals shown on the schedules of retirements and exposures, Tables 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of

TABLE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2000-2009
SUMMARIZED BY AGE INTERVAL

Experience Band 2000-2009 | Placement Band 1995-2009

	Exposures, Thousands of Dollars											
	Annual Survivors at the Beginning of the Year										Total at Beginning of Age	
Year Placed	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1995	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1996	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1997	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1998	338	330	321	311	300	289	276	262	242	226	823	10½-11½
1999	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2000	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2001		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2002			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2003				580[a]	574	561	546	530	501	482	3,057	5½-6½
2004					660[a]	653	639	623	628	609	3,789	4½-5½
2005						750[a]	742	724	685	663	4,332	3½-4½
2006							850[a]	841	821	799	4,955	2½-3½
2007								960[a]	949	926	5,719	1½-2½
2008									1,080[a]	1,069	6,579	½-1½
2009											7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

TABLE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2000-2009 Placement Band 1995-2009

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.
Column 3 from Table 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ as shown in Table 4 are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Tables 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

The original survivor curve is plotted from the original life table (column 6, Table 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

<u>Smoothing the Original Survivor Curve</u>. The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any

irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Table 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

<u>Field Trip</u> In order to be familiar with the Company and observe a representative portion of the plant, field trips are often conducted. Gannett Fleming, has in prior depreciation studies, completed field trips, and did not view the time and cost associated with extensive field trips to provide any significant benefit in the completion of this current study. Rather, Gannett Fleming asked to only visit the Liquified Natural Gas ("LNG") terminal on Vancouver Island during the course of this study.

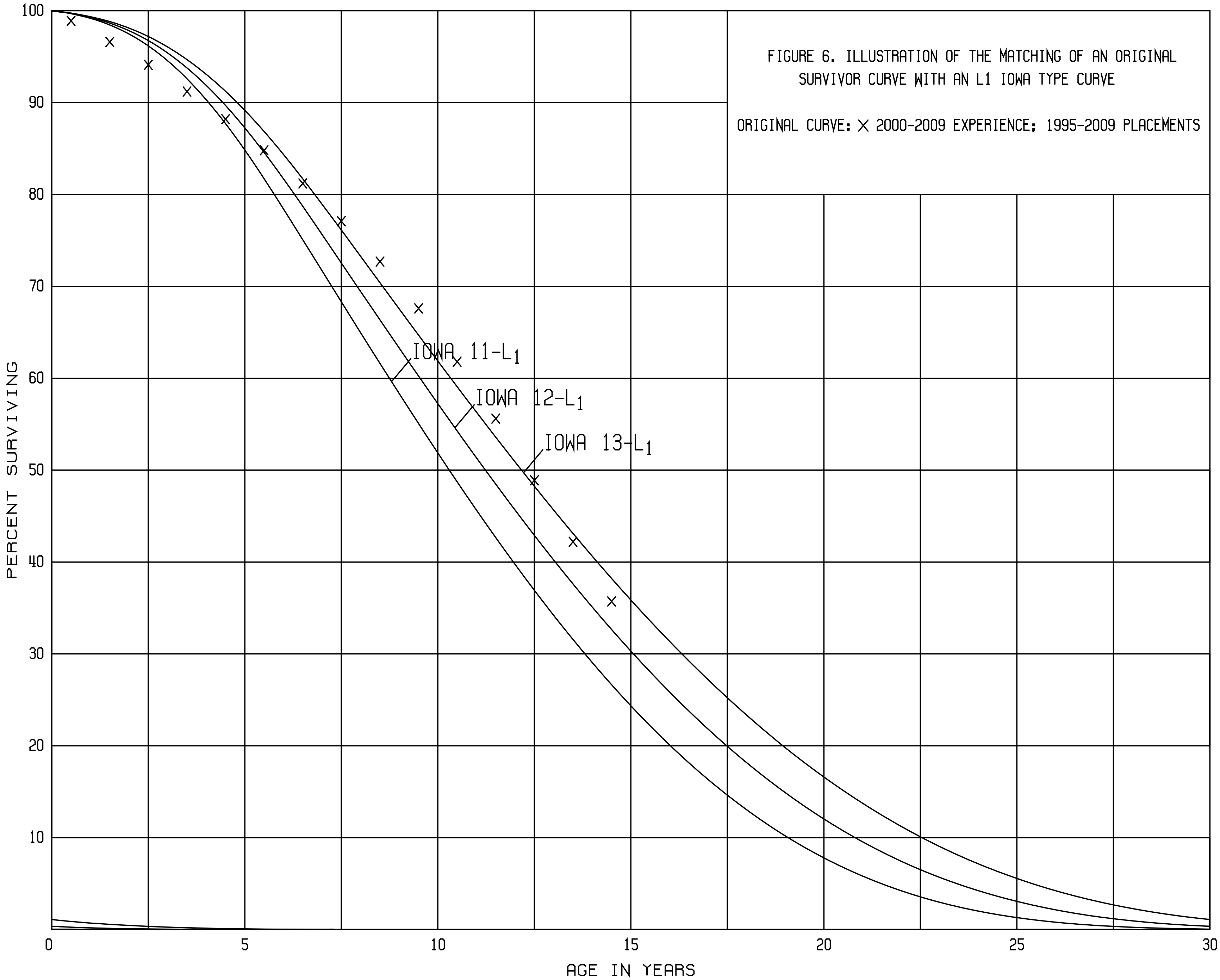


FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE

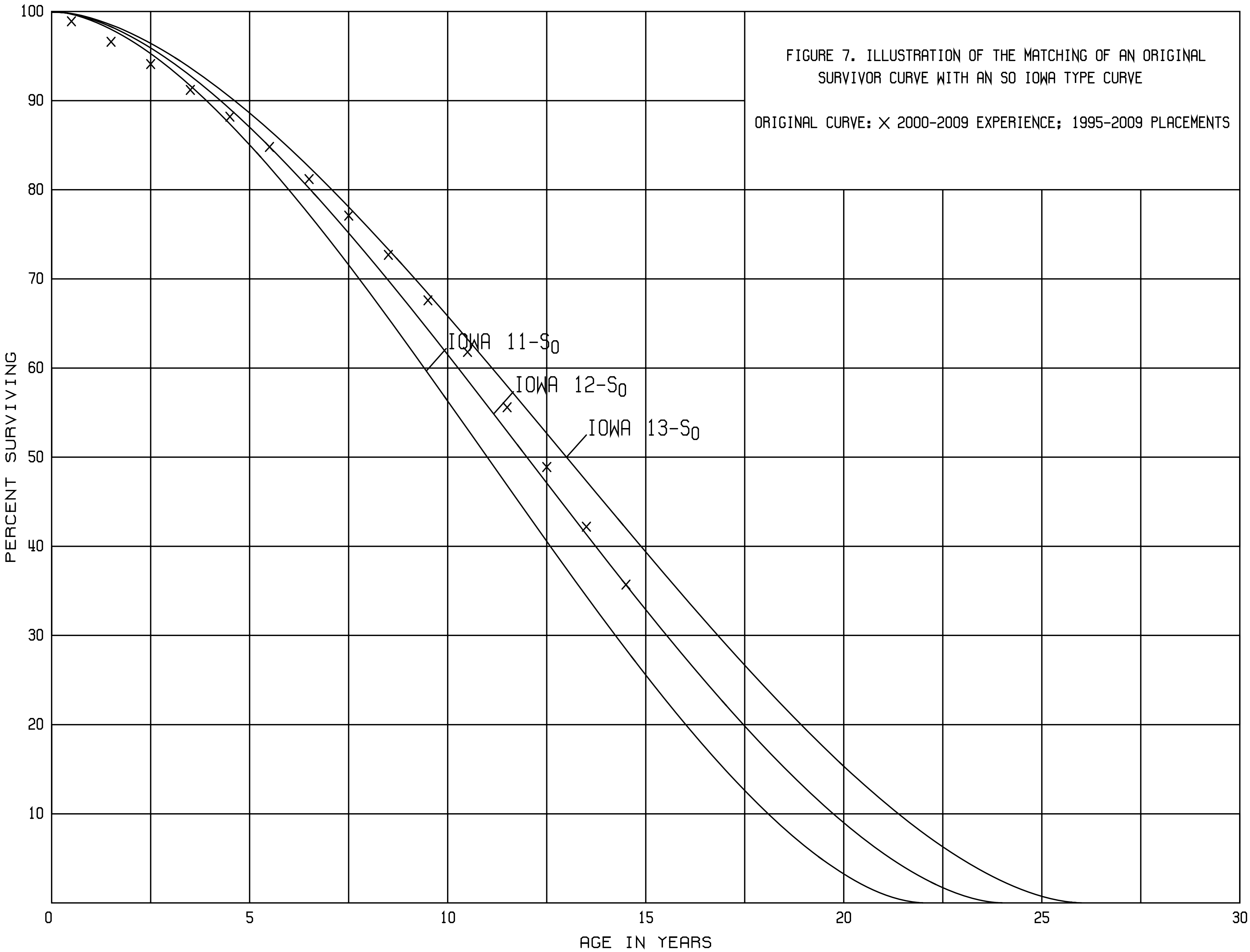


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN SO IOWA TYPE CURVE

ORIGINAL CURVE: × 2000-2009 EXPERIENCE; 1995-2009 PLACEMENTS

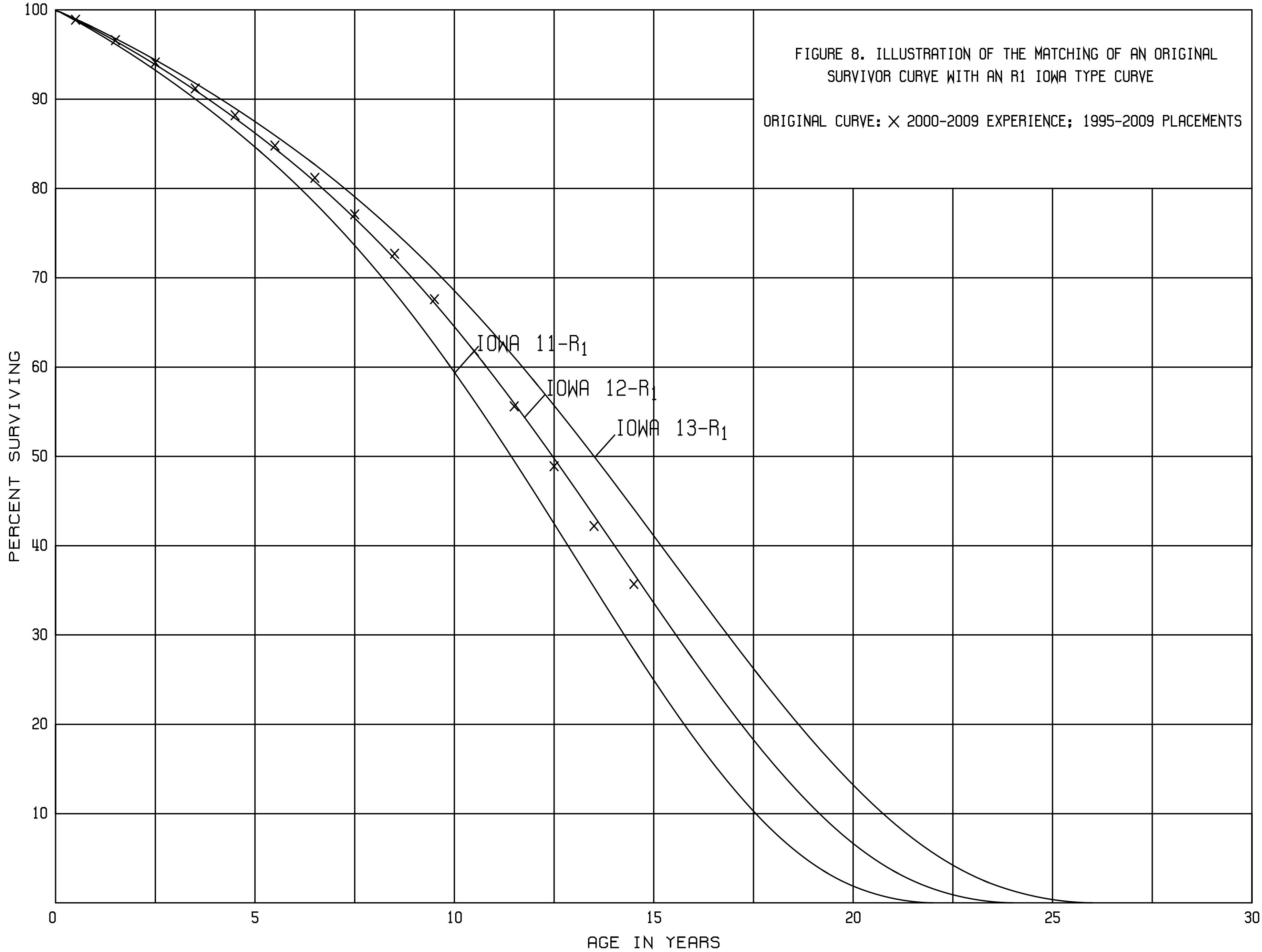


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL CURVE: × 2000-2009 EXPERIENCE; 1995-2009 PLACEMENTS
IOWA 11-R1
IOWA 12-R1
IOWA 13-R1
PERCENT SURVIVING
AGE IN YEARS
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30

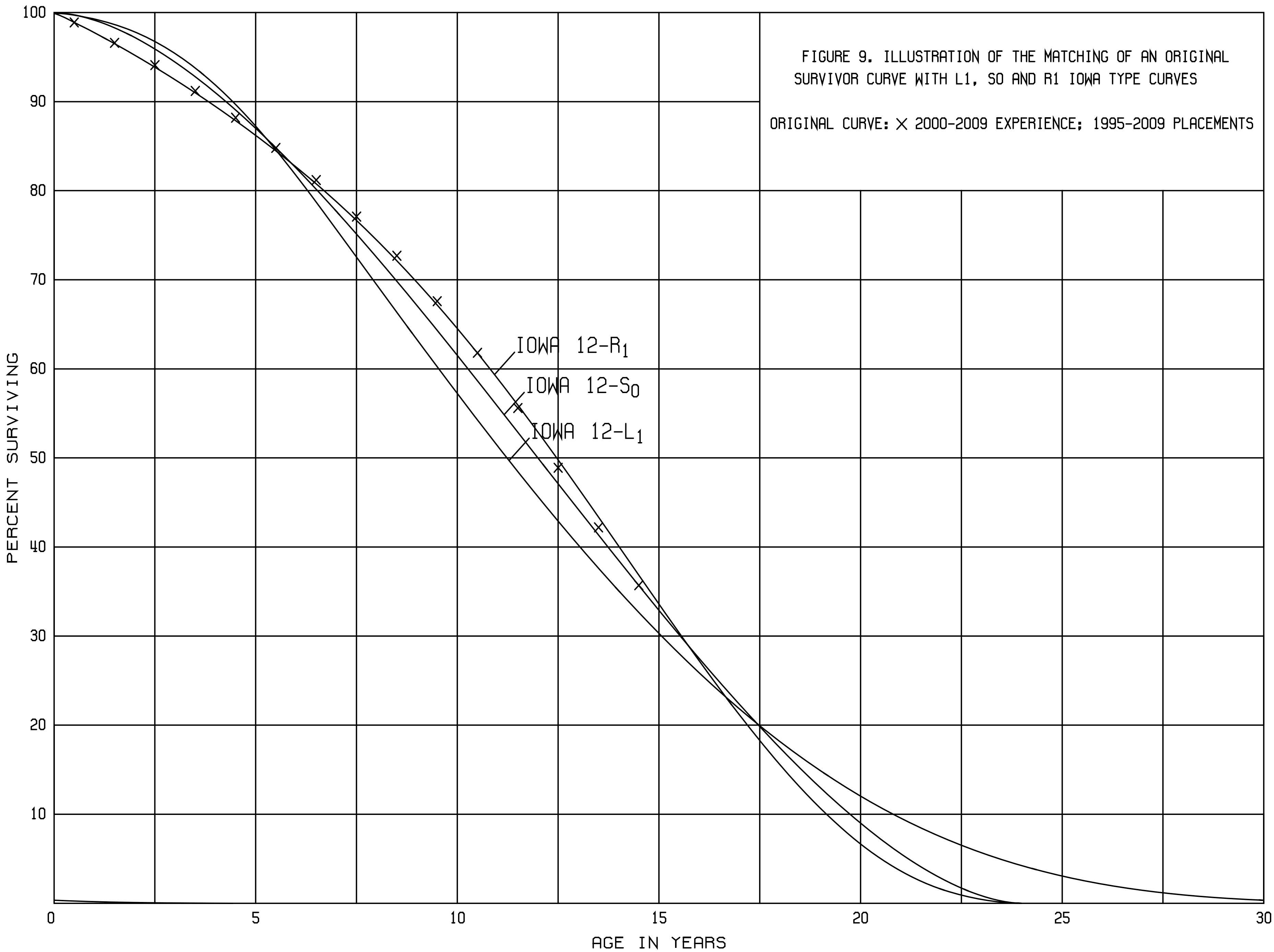


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH L1, SO AND R1 IOWA TYPE CURVES

Operational Interviews. Interviews and discussions were held with a number of operational and engineering groups. The interviews and discussions, combined with the information gained in the interviews and discussions from prior depreciation studies, assisted Gannett Fleming in the understanding of the historic forces of retirement that have resulted in the statistically developed average service life indications and on the anticipated future forces of retirement. Based on these discussions, Gannett Fleming is better able to determine if the results of the retirement rate analysis should be adjusted to better reflect the future forces of retirement, or changes in technology. Additionally, operational interviews provide information regarding the reuse practices and policies and cost of retirement information.

The following groups were interviewed by Gannett Fleming during the Depreciation Study:

- Information Systems
- Transmission
- Compression
- Distribution
- Metering
- Communication Systems
- Vehicle and Fleet
- Facilities

The information gained from these interviews was used in combination with the retirement rate study, comparisons to peers and the experience of Gannett Fleming in the final determination of average service life estimates and net salvage percentages.

Survivor Curve Judgments. Each retirement rate analysis resulted in a life table which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics, interpretation of the original survivor curves is required to use them as valid considerations in service life estimation. Iowa type curves were used in these interpretations. The survivor curve estimates were based on judgment which considered a number of factors as discussed above. The primary factors were the statistical analysis of data, current policies and outlook as determined during conversations with management and the field trip, and survivor curve estimates from previous studies of this Company and other gas transmission and distribution companies. The specific factors for the largest accounts follow.

Account 475.00 – Dist. Systems - Mains, is the largest account studied and represents 26% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2009 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-37. Typical service lives for distribution mains range from 50 to 65 years.

In previous studies Gannett Fleming recommended the Iowa 60-R3. The statistical analysis of this account has indicated a best fit of historic retirements consistent with the 64-R2 Iowa curve. Since the last study, this account has continued to incur retirements at a consistent rate which provide for a reliable statistical indication of average service life characteristics. To date, this account has experienced nearly

$36 million of retirement actively. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic pattern. Furthermore, operations staff has indicated that it would be expected that the life of the FortisBC distribution mains would be in the range of other industry peers and with the FortisBC Transmission mains. Typical service lives for distribution mains range from 50 to 65 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 50 years of age, with large retirement ratios through to age 75. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 64-R2 survivor curve to better reflect the trend towards increased retirement rates beyond age 50 as compared to the previous estimate of the 60-R2.5. This minor decrease in the mode of the Iowa curve combined with a small increase in the average service life expectation provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is therefore recommend for this account.

Account 465.00 – Trans. Plant – Trans. Pipeline, represents approximately 22% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1957 through 2009 were studied. The original survivor curve as plotted on page IV-16 indicates only a modest level of retirements through age 45. Typical service lives for transmission mains range from 50 to 70 years. Previous depreciation studies have indicated a 60-R3 Iowa curve for this account.

The Retirement Rate Analysis as presented at page IV-17 of this report and discussions with the operations and engineering staff have indicated that to date the pipe has experienced only a limited level of retirement activity. However, the retirement activity to date of over $10 Million of originally installed cost, has provided some data upon which a life analysis can be made, particularly when combined with the experience of the operations staff.

The mortality study produced a statically based best fit consistent with the Iowa 70-R3 curve. However the Operations staff felt that the future retirement patterns may differ from those witnessed to date. Operations staff has indicated that the original system consisting of pipes ranging from 12 inches to 3 inches, installed in 1957 represents about 30 to 40 percent of the currently installed transmission pipe. This pipe was not initially cathodically protected. However the cathodic protection was gradually added in the late 1960's with cathodic protection added to the 10 inch line after 10 years of service. FortisBC does internally inspect the transmission lines using inspection pigs through an on-going inspection program which began in the mid 1980's. Recent inspections have indicated some corrosion in the 10-inch line. Additionally the Operations staff indicated that the following retirement programs will be undertaken over the next few years:

- A number of specific mainline segments identified during seismic inspections;
- A number of river crossings;

Additionally, the company is reviewing a number of other potential transmission system programs to deal with changing supply and market demands.

In previous studies Gannett Fleming recommended an Iowa 60-R3 curve. However, the average service life in this study has been lengthened to an Iowa 65-R3 to better fit the historic retirement activity, but still recognize the anticipated increased level of retirements in future years. The Iowa 65-R3 survivor curve, selected in this study to represent the life characteristics for this account, is within the typical range of lives used for transmission mains in the industry, and conforms to the expectations of management.

Account 473.00 – Dist. Systems - Services, represents 20% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2009 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-30.

In previous studies Gannett Fleming recommended the Iowa 55-R2.5. Since the last study, this account has continued to incur retirements due to a number of retirement programs, which provides for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $64 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic patterns. Furthermore, operations staff have indicated that it would be expected that the life of the FortisBC distribution services would be in the range of other industry peers. Typical service lives for distribution services range from 40 to 65 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 20 years of age, with large retirement rates through to age 75. In order to better fit to this retirement pattern, Gannett Fleming has recommended the Iowa 50-R1 survivor curve to better reflect the trend toward increased retirement rates beyond age 40, as compared to the previous estimate of the Iowa 55-R2.5. This decrease in both the mode of the Iowa curve and the average service life expectation provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is, therefore recommended for this account.

Account 478.10, Dist. Systems - Meters, represents 6% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2009 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page IV-50. In recent years, the gas distribution industry has been moving toward increased used of digital metering and Automated Meter Reading (AMR) technology. Additionally, in early 2010, Measurement Canada has announced more stringent metering testing guidelines. The new testing guidelines place increasingly strict criteria on the test results as the age of the meters increase.

Interviews with the operational metering staff have indicated that the implementation of the new Measurement Canada requirements will result in residential meters continuing to be retired by the time they reach 20 years of age. In the experience of Gannett Fleming, this assumption is consistent with the metering experts across Canada, all of whom have indicated that residential meters will no longer be tested when they reach 15 to 20 years of age. Operations staff did indicate that the meters related to commercial and industrial customers are expected to last beyond 20 years, and would likely be refurbished when removed for testing. It is estimated that these larger commercial and industrial meters comprise less than 25% of the investment in this account.

Since the previous Gannett Fleming study which recommended an Iowa 25-R2-Iowa curve to represent the retirement characteristics for this account, FortisBC has continued the program to replace a older electro-mechanical meters with newer technology digital metering equipment. The retirement rate analysis for this account, as presented at page IV-51, indicates retirement activity throughout the accounts life constant with an Iowa 21-R2.5. This account is experiencing significant change in both the capitalization policies and in the technology associated with the assets within this account. Therefore, given the future expectation that residential meters will be retired prior to reaching an age of 20 years, the Iowa 20-R2 has been selected for this account. This account will be closely monitored over the next few years to determine if a shortening of the average service life estimate becomes necessary.

<u>Account 466.00 – Trans. Plant - Compressor Equipment</u>, represents approximately 3% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1973 through 2009 were analyzed by the retirement rate method. The original survivor curve as plotted on page IV-19 indicates only a modest level of historical retirements through age 15, and a significantly faster rate of retirement from ages 16 through 30.

In previous depreciation studies, Gannett Fleming has recommended a 33-R3 Iowa curve. Typical service lives for compression equipment range from 25 to 35 years. The compression units, utilized by FortisBC are Solar and Rolls-Royce units which have proven to be reliable both at FortisBC and within the industry as a whole. As such, it is expected that these units would perform at the longer end of the range of average service lives. However, the high rate of retirement ratios beginning at approximately age 15 need to be recognized. Gannett Fleming recommends a slight lengthening of the average service life to 35 years to deal with the company and industry experience.   As such, an adjustment to the Iowa 35-R3, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives used in the industry and anticipated by management.

The survivor curves for the remaining accounts were based on similar considerations of historical analysis, management outlook and estimates of this company and other gas distribution companies.

ESTIMATION OF NET SALVAGE

Appropriate depreciation policies should provide for the recovery of the service value of assets in regulatory service over the period of time for which the assets being depreciated are forecast to be in service. The total cost of an asset includes the original cost of the material and installation of the asset when originally placed into utility service. Additionally, at the time of retirement of an asset, the utility may be faced with significant costs associated with the removal and retirement of the asset. These retirement costs are directly related to the asset being removed at the end of its useful utility service.

The costs of removal are part of the overall costs of an asset to provide utility service and are considered to be part of the service value of the asset. The recovery of the cost of removal or retirement should be recovered over the service life of the asset. If the costs of retirement are deferred until after the assets are removed from service, an intergenerational issue develops wherein the future consumers that will be incurring the costs related to the recovery of the replacement asset, will also be responsible for the funding of the asset that has been removed and no longer provided service. In contrast, the recovery of the estimated costs of retirement (net of any potential salvage proceeds realized from the sale of assets to third parties or from re-use within the utility) over the period of time that the asset is providing utility service provides generational equity. The toll payers receive the benefit of an asset in service fund the total cost of the asset, including the eventual costs of retirement of the asset.

The concept of recovery of the total service value including both the original costs of the asset and the net salvage costs incurred at the time of retirement over the life of the assets useful service has been held by numerous regulatory jurisdictions throughout North America for many years.[9] As such, in the completion of the depreciation study for FortisBC, Gannett Fleming has developed appropriate net salvage rates, which when applied to the original cost of plant in service, will result in the provision of funds estimated to be required at the time of retirement.

Recently, the Canadian Accounting Standards Board has announced that Canadian Generally Accepted Accounting Principles (GAAP) will cease to exist as of 2011. From that date forward, companies will be required to report under International Financial Reporting Standards ("IFRS"). One of the areas of change relate to the depreciation of assets relating to net salvage requirements. In order to comply with these new standards, FortisBC has asked that Gannett Fleming prepare separate depreciation accrual rates specifically applicable to the net salvage requirements. As such, Schedule 1, as presented in the Results section of this report, provides for the recovery of the original cost of assets in service; and Schedule 2 separately provides for

[9] For example as identified by the FERC as noted in footnote 2 to this report and in the General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas Utilities under the Jurisdiction of the Public Utilities Board of the Province of Alberta, page 8

the recovery of the estimated costs of retirement. It is the recent experience of Gannett Fleming that regulated Canadian Utilities are complying with the IFRS in this manner.

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 2000 through 2009, and in part through a comparison to peer natural gas transmission and distribution companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases.

The net salvage percentages estimated in this study have been determined using the Traditional Approach for net salvage estimation. The estimates of net salvage were based in part on the database of historic transactions encompassing the period 2000 through 2009, as presented beginning on page of this report.

When a utility retires plant, the plant may be: (1) sold to a third party; (2) re-used by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceed (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage percentage results.

The estimation of the net salvage percentages developed using the traditional approach, included the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period January 1, 2000 through December 31, 2009 were extracted from the plant accounting systems.

2. A net salvage amount (gross salvage proceeds less cost of retirement) was calculated for each historic year. Additionally, a net salvage amount was also calculated for each historic 3-year rolling band and the most recent 5-year rolling band.

3. The net salvage amount determined above was compared to the original booked costs retired for each period in the manner described, which resulted in a net salvage percentage of original costs retired for each year, in addition to 3-year rolling bands and the most recent 5-year rolling band.

4. The annual, the 3-year rolling average, and the most recent 5-year rolling average net salvage percentages were analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage was based purely upon statistical analysis.

5. Each account was then compared to the net salvage percentage currently approved and compared to peer natural gas transmission and distribution companies. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Gannett Fleming, a net salvage percentage was determined for each account.

6. The net salvage percentage was then used in the depreciation rate calculations in the technical update.

Following is a brief summary by for each account where a net salvage recommendation is made, outlining the various factors considered by Gannett Fleming in forming the net salvage recommendation

<u>Account 442.00 – LNG Gas - Structures</u> - This account has very limited retirement and net salvage transaction history. Therefore the net salvage percentage of

-10% was based on the professional judgment of Gannett Fleming. As there is only limited experience throughout Canada of regulated LNG storage facilities, a peer analysis for this account was not completed. As part of the last depreciation study completed by Gannett Fleming, a site tour of the LNG facility was conducted. Additionally as part of this current depreciation study, a site tour of the facility currently under construction was completed, providing a prospective of the type of structures required for these facilities. Gannett Fleming views that upon retirement of the LNG facilities, a significant cost of removal will be required for the LNG structures and that a net salvage percentage of at least -10% is appropriate. A net salvage percentage of -10% was recommended in the last depreciation study, and Gannett Fleming recommends that, at this time, the -10% be continued. Gannett Fleming notes that the net salvage percentage may need to be increased in future studies, once this account begins to experience more retirement activity.

Account 443.00 – LNG Gas Equipment - A net salvage percentage of -20% was based on the professional judgment of Gannett Fleming. As there is only limited experience throughout Canada of regulated LNG storage facilities, a peer analysis for this account was not completed. As part of the last depreciation study completed by Gannett Fleming, a site tour of the LNG facility was conducted. Additionally as part of this current depreciation study, Gannett Fleming completed a site tour of the facility currently under construction. These site tours have provided Gannett Fleming with a prospective of the type of the large amount of specialized equipment required for these facilities. Gannett Fleming views that upon retirement of the LNG facilities, a significant cost of removal will be required for the LNG structures. The equipment and supporting infrastructure is very large, and in the view of Gannett Fleming a significant amount of labor will be required at the time of retirement for the decommissioning of these facilities. Therefore, Gannett Fleming views that a net salvage percentage of at least -20% is appropriate. A net salvage percentage of -20% was recommended in the last depreciation study, and Gannett Fleming recommends that, at this time, the -20% be continued. Gannett Fleming notes that the net salvage percentage need to be increased in future studies, once this account begins to experience more retirement activity.

Account 449.00 – LNG Gas – Other Equipment – This account has experienced a significant amount of retirements in 2008, resulting in a net salvage percentage of -16% in 2008. However, other years of minor retirement activity have resulted in no cost of removal expenditures.

As there is only limited experience throughout Canada of regulated LNG storage facilities, a peer analysis for this account was not completed. As part of the last depreciation study completed by Gannett Fleming, a site tour of the LNG facility was conducted. Additionally as part of this current depreciation study, Gannett Fleming completed a site tour of the facility currently under construction. These site tours have provided Gannett Fleming with a prospective of the type of the large amount of specialized equipment required for these facilities. Based on the cost of removal history and on the background gained through the site tours, Gannett Fleming recommends a net salvage percentage of -10%, which is consistent with the recommendation in the last depreciation study.

Account 462.00 – Compressor Structures – As indicated at page V-2 of this report, this account has experienced only minimal amounts of retirements over the past 10 years. As such, there was no retirement history upon which to base a statistical analysis of net salvage. However, Gannett Fleming did review the approved net salvage parameters of a peer group gas transmission companies as follows:

- ATCO Pipelines – (20)%
- AltaGas – 0%
- Manitoba Hydro/Centra Gas Manitoba- (5)%

Interviews were held where operational and management staff provided insight into the operations, policies and practices related to a number of asset types, including the Compressor Structures. During these interviews, the operations staff viewed that there would be a small amount of cost of removal associated with the Compression Structures at the time of retirement. As such, Gannett Fleming recommends a small provision of -5% for this account. This recommendation is consistent with the experience of Gannett Fleming within the industry, and also with the expectations of operational staff and management.

Account 463.00 – Measuring/Regulating Structures - As indicated at page V-3 of this report, this account has experienced only minimal amounts of retirements over the past 10 years. The minimal retirement activity has shown a net salvage percentage of -5%. However, given the minimal amount of activity, Gannett Fleming reviewed the approved net salvage parameters of a peer group gas transmission companies as follows:

- ATCO Pipelines – (15)%

- AltaGas – (10)%
- Manitoba Hydro/Centra Gas Manitoba- (5)%

Interviews were held where operational and management staff to provided insight into the operations, policies and practices related to a number of asset types, including the Regulating Structures. During these interviews, the operations staff viewed that there would be a small amount of cost of removal associated with the Regulating Structures at the time of retirement. As such, Gannett Fleming recommends a small provision of -5% for this account. This recommendation is consistent with the limited actual experience, is within the range of experience of Gannett Fleming within industry, and also with the expectations of operational staff and management.

Account 464.00 – Other Structures - As indicated at page V-4 of this report, this account has experienced only minimal amounts of retirements over the past 10 years. The minimal retirement activity that has shown a net salvage percentage of -85% has been discounted given the limited number of retirement transactions. Given the minimal amount of activity, Gannett Fleming reviewed the approved net salvage parameters of a peer group gas transmission companies as follows:

- ATCO Pipelines – (15)%
- AltaGas – N/A
- Manitoba Hydro/Centra Gas Manitoba - (5)%

Interviews were held where operational and management staff to provided insight into the operations, policies and practices related to a number of asset types, including the Regulating Structures. During these interviews, the operations staff viewed that there would be a small amount of cost of removal associated with the Regulating Structures at the time of retirement. It was considered that the other Transmission Structure accounts have been assigned a net salvage percentage of -5%. In order to maintain consistency with the other Structure accounts, Gannett Fleming recommends a small provision of -5% for this account. This recommendation is significantly lower than the limited actual experience, but is within the range of experience of Gannett Fleming within industry, and also with the expectations of operational staff and management.

Account 465.00 – Transmission Mains – As indicated in the net salvage analysis provided at page V-5, this account has witnessed a significant amount of retirement activity over the last 10-year period. The salvage analysis provides the annual net salvage percentage, a three-year rolling average and the most recent five-year rolling average. While these trends have all shown a large increase in net salvage requirements over the past few years, it has been indicated that the recent costs of removal have been related to an effort to clean up a backlog of required work. As such it felt that the longer term averages provide a better indication of the net salvage requirements. A review of peer natural gas utilities has indicated the following:

- ATCO Pipelines – (25)%
- AltaGas – (10)%
- Manitoba Hydro/Centra Gas Manitoba- (15)%

The Gannett Fleming recommendation to continue to use the current -10% is lower than the 10 year average, and at the lower end of the peer averages. However, Gannett Fleming believes that a longer period of increased net salvage indications is required prior to increasing the net salvage percentage. Therefore, the continuation of the -10% net salvage percentage is recommended.

Account 466.00 – Compressor Equipment – As indicated at page V-6 of this report, this account has experienced only minimal amounts of retirements over the past 10 years. The minimal retirement activity that has shown a net salvage percentage of -19% has been discounted given the limited number of retirement transactions. Given the minimal amount of activity, Gannett Fleming reviewed the approved net salvage parameters of a peer group gas transmission companies as follows:

- ATCO Pipelines – (10)%
- AltaGas – N/A
- Manitoba Hydro/Centra Gas Manitoba- N/A

During interviews with the operations staff it was indicated that there would be a small amount of cost of removal associated with the compression equipment at the time of retirement. While the recommendation of -10% is lower than the limited actual experience, it is within the range of experience of Gannett Fleming within the industry, and also with the expectations of operational staff and management.

Account 467.10 – Transmission Measuring/Regulating Equipment - As indicated in the net salvage analysis provided at page V-7, this account has witnessed a significant amount of retirement activity over the last 10 year period. The salvage analysis provides the annual net salvage percentage ranging from 0% to -25%, in addition to three-year rolling averages ranging from -3% to -11%, and the most recent five-year rolling average indicating -7%. A review of peer natural gas utilities has indicated the following:

- ATCO Pipelines – (15)%
- AltaGas – (50)%
- Manitoba Hydro/Centra Gas Manitoba- (5)%

The Gannett Fleming recommendation to continue to use the current -5% is consistent with the statistical analysis performed, and is consistent (although at the lower end) of the peer averages.

Account 472.00 – Distribution Structures - As indicated in the net salvage analysis provided at page V-10, this account has witnessed a moderate amount of retirement activity over the last 10 year period. The salvage analysis provides the annual net salvage percentage, a three-year rolling average and the most recent five-year rolling average. While these trends have all shown a large increase in net salvage requirements over the past few years, the increases have been on small amounts of original costs retired. A review of peer natural gas utilities has indicated the following:

- ATCO Gas – (40)%
- Enbridge Gas Distribution – (5)%
- AltaGas – 0%
- Manitoba Hydro/Centra Gas Manitoba- (10)%
- SaskEnergy – (5)%

The Gannett Fleming recommendation to continue to use the current -5% is lower than the 10 year average, and within the peer averages. Additionally, the recommended -5% is consistent with the Transmission structure accounts.

Account 473.00 – Distribution Services – As indicated in the net salvage analysis provided at page V-11, this account has witnessed a significant amount of retirement activity over the last 10 year period. The salvage analysis provides annual net salvage percentages ranging from 0% to -153%, in addition to three-year rolling averages ranging from -11% to -153%, and the most recent five-year rolling average indicating -49%. A review of peer natural gas utilities has indicated the following:

- ATCO Gas – (100)%
- Enbridge Gas Distribution – (45)%
- AltaGas – (75)%
- Manitoba Hydro/Centra Gas Manitoba- (25)%
- SaskEnergy – (40)%

The Gannett Fleming recommendation to continue to use the current -50% is predominately based on the statistical analysis, and is within the range of the peer averages. However, it is noted that the recent trends from 2003 through 2009, in many years have indicated a net salvage percentage in excess of -100%. In future studies, if these trends continue, increased amounts of net negative salvage will be required.

Account 475.00 – Distribution Mains – As indicated in the net salvage analysis provided at page V-13, this account has witnessed a significant amount of retirement activity over the last 10 year period. The salvage analysis provides annual net salvage percentages ranging from 0% to -89%, in addition to three-year rolling averages ranging from -1% to -70%, and the most recent five-year rolling average indicating -15%. A review of peer natural gas utilities has indicated the following:

- ATCO Gas – (60)%
- Enbridge Gas Distribution – (75)% to (145)%
- AltaGas – (10)%
- Manitoba Hydro/Centra Gas Manitoba- (20)%
- SaskEnergy – (10)%

The Gannett Fleming recommendation to continue to use the current -20% is predominately based on the statistical analysis, and is within the range of the peer averages. However, it is noted that the recent trends from 2003 through 2009, in many years have indicated a net salvage percentage in excess of -20%. In future studies, if these trends continue, increased amounts of net negative salvage will be required.

Account 476.00 – NGV Fuel Equipment - This account has not occurred any retirement activity since the year 2000, and no net salvage transactions. As the investment in this account relates to equipment that will be labor intensive to remove, Gannett Fleming views that a net salvage percentage that result in excess of $100,000 will be required. Additionally, the retirement booked in the year 2000, may have physical plant to remove for the investment dollars have been previously retired. Therefore, only a small amount of investment remains in this account, which will be the basis for the accrual of all of the required cost of removal expenditures. It is the view of Gannett Fleming that a net salvage percentage of -20% is required to collection of the funds required for the removal of the physical plant.

Account 477.30 – Distribution Measuring and Regulating Equipment – The historic retirement and net salvage transactions for this account have been previously recorded in Account 477.10. As such the statistical analysis of net salvage is based on the history as indicated at page V-15 of this report. The historic investment in account 477.10 indicates a significant level of retirement experience, with an overall 10 year average net salvage indication of -10%. The three-year rolling average net salvage indications have typically indicated a net salvage requirement of approximately -15%., which is consistent with the most recent five-year average. A review of peer natural gas utilities has indicated the following:

- ATCO Gas – (40)%
- Enbridge Gas Distribution – (10)%
- AltaGas – (15)%
- Manitoba Hydro/Centra Gas Manitoba- (20)%
- SaskEnergy – (5)%

The Gannett Fleming recommendation to continue to use the current -5% is predominately based on the statistical analysis, and is at the low end, but within the range of the peer averages. However, it is noted that the recent trends have indicated a net salvage percentage in excess of -5%. In future studies, if these trends continue, increased amounts of net negative salvage will be required.

<u>Account 477.30 – Distribution Meters</u> – The historic retirement trend relating to the retirement and replacement of meters has been largely discounted in this study. As indicated at page II-29 of this report, the rate of retirements of the meters currently in place is expected to dramatically accelerate over the next few years, due to recently announced Measurement Canada guidelines and the implementation of an AMR

program. The program nature of the retirement of meters currently in place will result in increases in costs of retirement. Historically, costs of retirement have been offset by the ability to sell used meters to third parties or to re-use meters within the FortisBC Energy system. However, given the change in technology, and the amount of used analog meters available throughout the North American marketplace, it is Gannett Fleming's view that a resale or reuse market does not exist. Therefore a small net salvage provision of -5% is recommended.

Account 484.00 – Vehicles – Interviews with operational and accounting staff have indicated that net salvage proceeds related to the sale of vehicles have only been separately recorded since 2008. Therefore a detailed database with historic sales transactions is not available. Prior to 2008, the trade-in value of used vehicles was offset against the purchase cost of the replacement vehicle. As such, Gannett Fleming has relied on the limited amount of the two years experience, but also on the comments of the fleet management group, and on the peer group in the development of the net salvage recommendations.

A review of peer natural gas utilities has indicated the following:

- ATCO Gas – 25%
- Enbridge Gas Distribution – 15%
- AltaGas – 25%
- Manitoba Hydro/Centra Gas Manitoba- 15%
- SaskEnergy – 20%

Interviews with the Fleet Management group indicated an expectation of positive salvage proceeds of at least 20%. As this is consistent with the peer group experience, Gannett Fleming recommends the continuation of the 20% net salvage percentage.

Account 485.10 – Heavy Work Equipment – Interviews with operational and accounting staff have indicated that net salvage proceeds related to the sale of heavy work equipment have only been separately recorded since 2008. Therefore a detailed database with historic sales transactional is not available. Prior to 2008, the trade-in value of work equipment was offset against the purchase cost of the replacement equipment. As such, Gannett Fleming has relied on the comments of the fleet management group, and on the peer group in the development of the net salvage recommendations.

A review of peer natural gas utilities has indicated the following:

- ATCO Gas – 30%
- Enbridge Gas Distribution – 25%
- AltaGas – 20%
- Manitoba Hydro/Centra Gas Manitoba- 20%
- SaskEnergy – 20%

Interviews with the Fleet Management group indicated an expectation of positive salvage proceeds of at least 15%. Although this is lower than the peer group experience, given the low volume of sale transactions, Gannett Fleming recommends the continuation of the 15% net salvage percentage.

Account 485.20 – Heavy Mobile Equipment - Interviews with operational and accounting staff have indicated that net salvage proceeds related to the sale of heavy mobile equipment have only been separately recorded since 2008. Therefore a detailed database with historic sales transactional data is not available. Prior to 2008, the trade-in value of the equipment was offset against the purchase cost of the replacement equipment. As such, Gannett Fleming has relied on the comments of the fleet management group, indicating an expectation of 10% upon resale. This equipment is not typically separated in the circumstances of the peer group of companies; therefore a peer analysis was not undertaken. Based on the comments of the fleet management group, the continuation of the 10% net salvage percentage is recommended.

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the average service life and equal life group procedures.

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than full y recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit. Although the equal life group procedure is superior to the average service life procedure in matching depreciation expense and consumption of service value, the average service life procedure was used in order to conform to past Company practices and for consistency with practices of other companies regulated by the British Columbia Utilities Commission.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

	Account	Amortization Period Years
483.10	Computer Hardware	5
483.20	Computer Software	5 and 8
483.30	Office Equipment	15
483.40	Office Furniture	20
486.00	Small Tools/Equipment	20
487.20	NGV Cylinders	15
488.10	Telephone Equipment	15
488.20	Radio Equipment	15

The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the original cost by the period of amortization for the account for those vintages with an age less than the amortization period.

In addition to the above accounts, amortization accounting is recommended for a new account 474.02 - Distribution Systems Meters/Regulator Installations. This account is used to capture new plant additions in this category. Rather than relying on individual retirement of assets in this category which are wide and disparate, an alternative and representative approach to follow an amortization accounting is recommended. Additions to the account will be depreciated at an initial whole life rate of 4.5%, representative of an expected life of 22 years. The existing meter install costs would remain in the current account (474.00) and continue depreciating at the recommended depreciation rate, which includes a factor for recovery of existing retirement losses

PART III. RESULT OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculation of the composition remaining lives and the determination of the annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revision are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage, and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line average service life method of depreciation based on estimates which reflect consideration of current historical evidence and expected future conditions. The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals if current forecasts of service life and salvage materialize and are used as a basis for straight line average service life depreciation accounting.

DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of gas plant of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. as of December 31, 2009, are presented in Tables 1 and 2 attached to this report. Table 1 sets forth the original cost, the booked accumulated depreciation amounts, and the required future accruals prior to consideration of the net salvage provision for FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and

FortisBC Energy (Whistler) Inc. As such, Table 1 for each system provides for the recovery of the original costs of the assets within each system. Table 2 presents the calculations related to the recovery of the net salvage requirements for each of the same three systems.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and operating staff, and consideration of estimates made for other gas companies as discussed in Part II of this report. For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table plotted on the charts is presented starting at page lV-2. The survivor curve estimated for the depreciable groups is shown as a dark smooth curve on the charts. Each smooth curve is denoted by a numerical average service life indication followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of each chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables that are plotted. The experience band indicates the range of years fro which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual and accrued depreciation are presented in account sequence in the section beginning on V-2**.** The tables are first presented for all of the FortisBC accounts, followed by all of the FortisBC Energy (Vancouver Island) Inc. accounts and then for all accounts related to FortisBC Energy (Whistler) Inc. Each table indicates the estimated survivor curve and net salvage percent for the account; and sets forth, for each installation year, the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

FORTISBC ENERGY INC.

SCHEDULE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	Intangible Plant								
401.01	Franchises and Consents	40-SQ	0%	99,236.40	49,827	49,409	48,813	49.19%	1.0
402.01	Computer Software Application 8 Years	8-SQ	0%	49,631,449	24,126,327	25,505,122	6,203,932	12.50%	4.4
402.02	Computer Software Application 5 Years	5-SQ	0%	8,350,195	1,980,513	6,369,682	1,670,039	20.00%	3.4
402.03	Intangible Plant	40-SQ	0%	687,555	164,879	522,676	16,334	2.38%	32.0
402.11	Intangible Plant	40-SQ	0%	62,457	26,771	35,686	35,686	57.14%	1.0
	Total Intangible Plant			**58,830,892**	**26,348,317**	**32,482,575**	**7,974,804**		
	Manufacturing Plant								
432.00	Mfg. Gas Structures	40-SQ	0%	463,510	99,580	363,930	15,680	3.38%	23.2
433.00	Mfg. Gas Equipment	20-SQ	0%	145,938	51,466	94,472	9,681	6.63%	9.8
434.00	Mfg. Gas Holders	40-SQ	0%	357,585	172,949	184,636	8,388	2.35%	22.0
436.00	Mfg. Gas Compressor Equipment	25-SQ	0%	53,309	23,271	30,038	2,753	5.16%	10.9
437.00	Mfg. Gas Meas. & Reg. Equipment	20-SQ	0%	309,447	152,082	157,365	49,182	15.89%	3.2
	Total Manufacturing Plant			**1,329,789**	**499,348**	**830,441**	**85,684**		
	LNG Plant								
442.00	LNG Gas - Structures	25-L2	0%	4,884,581	2,047,606	2,836,975	174,558	3.57%	16.3
443.00	LNG Gas - Equipment	40-L4	0%	16,494,017	8,119,663	8,374,354	319,099	1.93%	26.2
449.00	LNG Gas - Other Equipment	27-R3	0%	22,977,022	7,335,927	15,641,095	975,058	4.24%	16.0
	Total LNG Plant			**44,355,620**	**17,503,196**	**26,852,424**	**1,468,715**		
	Transmission Plant								
462.00	Trans. Plant - Compressor Structures	30-R4	0%	14,705,802	4,945,516	9,760,286	549,370	3.74%	17.8
463.00	Trans. Plant - Meas. & Reg. Structures	30-S1	0%	4,993,568	1,208,841	3,784,727	189,509	3.80%	20.0
464.00	Trans. Plant - Other Structures	35-R3	0%	6,008,201	1,304,887	4,703,314	170,279	2.83%	27.6
465.00	Trans. Plant - Trans. Pipeline	65-R3	0%	719,965,381	165,817,556	554,147,825	10,336,304	1.44%	53.6
466.00	Trans. Plant - Compressor Equipment	35-R3	0%	106,260,667	31,714,939	74,545,728	3,054,833	2.87%	24.4
467.10	Trans. Plant - Meas. & Reg. Equipment	27-L1	0%	28,678,532	5,072,002	23,606,530	1,224,947	4.27%	19.3
467.20	Trans. Plant - Telementry Equipment	15-L1	0%	6,380,514	**6,105,941**	274,573	19,602	0.31%	14.0
467.30	Trans. Plant - Meas. & Reg. Equipment					-		0.00%	
468.00	Trans. Plant - Communications Equipment	12-R2.5	0%	345,885	266,836	79,050	15,118	4.37%	5.2
	Total Transmission Plant			**887,338,551**	**216,436,517**	**670,902,033**	**15,559,962**		
	Distribution Plant								
472.00	Dist. Systems - Structures	29-L0.5	0%	15,197,479	3,040,687	12,156,792	505,802	3.33%	24.0
473.00	Dist. Systems - Services	50-R1	0%	634,879,068	41,827,912	593,051,156	14,509,641	2.29%	40.9
473.01	LILO - Dist. Systems - Services	40-SQ	0%	43,176,583	10,317,234	32,859,349	2,551,016	5.91%	12.9
474.00	Dist. Systems - Meters/Reg. Installations	22-R2.5	0%	133,486,838	1,778,650	131,708,188	9,928,321	7.44%	13.3
474.01	LILO - Dist. Systems - Meters/Reg. Installations	30-SQ	0%	16,070,133	8,271,355	7,798,778	597,362	3.72%	13.1
474.02	New Meter Installations	22-SQ	0%	-		-		4.55%	
475.00	Dist. Systems - Mains	64-R2	0%	842,653,104	194,254,412	648,398,692	12,477,203	1.48%	52.0
475.01	LILO - Dist. Systems - Mains	40-SQ	0%	39,765,088	15,648,839	24,116,249	1,804,663	4.54%	13.4
476.00	Dist. Systems - NGV Fuel Equipment	7-R0.5	0%	570,858	305,975	264,883	151,484	26.54%	1.7
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	77,892,235	13,463,590	64,428,645	3,700,846	4.75%	17.4
477.20	Dist. Systems - Telemetry	27-R1.5	0%	5,741,611	6,306,919	(565,308)			
477.30	Dist. Systems - Meas. & Reg. Equipment	15-R2.5	0%	163,151	200,186	(37,035)			
478.10	Dist. Systems - Meters	20-R2.5	0%	187,877,053	40,426,723	147,450,330	14,829,932	7.89%	9.9
478.11	LILO - Dist. Systems - Meters	25-SQ	0%	10,026,725	4,067,086	5,959,639	524,229	5.23%	11.4
478.20	Dist. Systems - Instruments	35-R5	0%	11,305,173	2,814,191	8,490,982	356,530	3.15%	23.8
	Total Distribution Plant			**2,018,805,099**	**342,723,760**	**1,676,081,340**	**61,937,029**		

FORTISBC ENERGY INC.

SCHEDULE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	General Plant								
482.10	General Plant - Structures (Frame)	20-L0.5	0%	6,435,259	1,915,207	4,520,052	310,179	4.82%	14.6
482.20	General Plant - Structures(Masonry)	45-R1.5	0%	82,562,577	9,557,435	73,005,142	1,842,337	2.23%	39.6
482.30	General Plant - Structures (Leased)	20-R0.5	0%	127,332	372,709	-245,377			
483.10	Computer Hardware	5-SQ	0%	19,520,787	8,363,842	11,156,945	3,904,157	20.00%	2.8
483.20	Computer Software 12.5%	8-SQ	0%	1,652,148	479,396	1,172,752	206,518	12.50%	6.1
483.21	Computer Software 20%	5-SQ	0%	68,191	1,712	66,479	13,638	20.00%	4.9
483.30	Office Furniture and Equipment	15-SQ	0%	3,357,299	1,287,522	2,069,777	223,819	6.67%	7.1
483.40	Furniture	20-SQ	0%	20,004,722	11,847,651	8,157,071	1,000,237	5.00%	8.4
484.00	Vehicles	5-L0.5	20%	963,929	539,791	231,352	49,723	5.16%	4.7
485.10	Heavy Work Equipment	10-L0.5	15%	212,022	61,179	119,039	19,005	8.96%	6.3
485.20	Heavy Mobile Equipment	7-R1.5	10%	500,622	92,864	357,695	90,403	18.06%	4.0
486.00	Small Tools/Equipment	20-SQ	0%	37,003,661	14,421,301	22,582,360	1,850,182	5.00%	12.2
487.20	NGV Cylinders	15-SQ	0%	24,167	6,688	17,479	1,611	6.67%	12.2
488.10	Telephone Equipment	15-SQ	0%	8,000,183	4,826,869	3,173,314	533,348	6.67%	7.1
488.20	Radio Equipment	15-SQ	0%	4,988,323	2,431,344	2,556,979	332,553	6.67%	10.1
	Total General Plant			**185,421,225**	**62,648,391**	**128,941,062**	**10,377,710**		
	TOTAL DEPRECIABLE PLANT			**3,196,081,176**	**666,159,529**	**2,536,089,876**	**97,403,904**		
	PLANT NOT STUDIED								
430.00	Manufacturing Plant - Land								
440.00	LNG Gas - Land								
460.00	Trans. Plant - Land								
465.10	Trans. Plant - Trans. Pipeline - Bryon Creek								
470.00	Dist. Systems - Land								
472.10	Dist. Systems - Structures - Bryon Creek								
461.10	Trans. Plant - Land Rights - Bryon Creek								
471.10	Dist. Systems - Land Rights - Bryon Creek								
480.00	General Plant - Land								
	TOTAL NON - DEPRECIABLE PLANT								
	TOTAL PLANT			**3,196,081,176**	**666,159,529**	**2,536,089,876**	**97,403,904**		

FORTISBC ENERGY INC.

SCHEDULE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	LNG Plant								
442.00	LNG Gas - Structures	25-L2	-10%	4,884,581	204,656	283,802	17,464.72	0.36%	16.3
443.00	LNG Gas - Equipment	40-L4	-20%	16,494,017	1,564,043	1,734,761	66,111.32	0.40%	26.2
449.00	LNG Gas - Other Equipment	27-R3	-10%	22,977,022	917,589	1,380,113	86,041.98	0.37%	16.0
	Total LNG Plant			**44,355,620**	**2,686,288**	**41,669,332**	**169,618**		
	Transmission Plant								
462.00	Trans. Plant - Compressor Structures	30-R4	-5%	14,705,802	276,176	459,114	25,836.47	0.18%	17.8
463.00	Trans. Plant - Meas. & Reg. Structures	30-S1	-5%	4,993,568	72,410	177,268	8,876.71	0.18%	20.0
464.00	Trans. Plant - Other Structures	35-R3	-5%	6,008,201	67,160	233,250	8,444.97	0.14%	27.6
465.00	Trans. Plant - Trans. Pipeline	65-R3	-10%	719,965,381	16,345,416	55,651,122	1,038,073.54	0.14%	53.6
466.00	Trans. Plant - Compressor Equipment	35-R3	-10%	106,260,667	3,281,674	7,344,393	300,999.69	0.28%	24.4
467.10	Trans. Plant - Meas. & Reg. Equipment	27-L1	-5%	28,678,532	437,746	996,181	51,695.94	0.18%	19.3
467.20	Trans. Plant - Telementry Equipment	15-L1	0%	6,380,514	-	-		0.00%	14.0
467.30	Trans. Plant - Meas. & Reg. Equipment				-	-			
468.00	Trans. Plant - Communications Equipment	12-R2.5	-5%	345,885	-	17,294	3,306.74	0.96%	5.2
	Total Transmission Plant			**887,338,551**	**20,480,582**	**64,878,622**	**1,437,234**		
						-			
	Distribution Plant					-			
472.00	Dist. Systems - Structures	29-L0.5	-5%	15,197,479	184,102	575,772	23,960.56	0.16%	24.0
473.00	Dist. Systems - Services	50-R1	-50%	634,879,068	40,377,712	277,061,823	6,779,100.14	1.07%	40.9
473.01	LILO - Dist. Systems - Services	40-SQ	-50%	43,176,583	5,709,004	15,879,288	1,232,863.95	2.86%	12.9
474.00	Dist. Systems - Meters/Reg. Installations	22-R2.5	-10%	133,486,838	-	13,348,684	1,003,660.44	0.75%	13.3
474.01	LILO - Dist. Systems - Meters/Reg. Installations	30-SQ	0%	16,070,133	-	-	-	0.00%	13.1
475.00	Dist. Systems - Mains	64-R2	-20%	842,653,104	42,084,458	126,446,163	2,433,060.67	0.29%	52.0
475.01	LILO - Dist. Systems - Mains	40-SQ	-20%	39,765,088	2,707,439	5,245,579	391,461.12	0.98%	13.4
476.00	Dist. Systems - NGV Fuel Equipment	7-R0.5	-20%	570,858	-	114,172	65,240.88	11.43%	1.8
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	77,892,235	-	-		0.00%	17.4
477.20	Dist. Systems - Telemetry	27-R1.5	0%	5,741,611	-	-		0.00%	
477.30	Dist. Systems - Meas. & Reg. Equipment	15-R2.5	-5%	163,151	-	8,158	847.98	0.52%	9.6
478.10	Dist. Systems - Meters	20-R2.5	-5%	187,877,053	-	9,393,853	945,055.60	0.50%	9.9
478.11	LILO - Dist. Systems - Meters	25-SQ	0%	10,026,725	-	-	-	0.00%	11.4
478.20	Dist. Systems - Instruments	35-R5	0%	11,305,173	-	-	-	0.00%	23.8
	Total Distribution Plant			**2,018,805,099**	**91,062,714**	**448,073,490**	**12,875,251**		

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

SCHEDULE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	LNG PLANT - MT. HAYES ASSETS								
442.00	LNG Plant - Structures	25-SQ	0%					4.00%	
443.00	LNG Plant- Equipment	60-SQ	0%					1.67%	
448.1	LNG Plant - Piping	40-SQ	0%					2.50%	
448.2	LNG Plant- Pre-Treatment	25-SQ	0%					4.00%	
448.3	LNG Plant - Liquefaction Equipment	40-SQ	0%					2.50%	
448.4	LNG Plant- Send Out Equipment	40-SQ	0%					2.50%	
448.5	LNG Plant- Sub-Station and Electrical	40-SQ	0%					2.50%	
448.6	LNG Plant- Control Room	15-SQ	0%					6.67%	
465.0	Mt. Hayes - Mains	65-SQ	0%					1.54%	
467.0	Mt. Hayes - Measuring and Regulating Equipment	27-SQ	0%					3.70%	
	TOTAL LNG PLANT - MT HAYES ASSETS								
	NATURAL GAS & PETROLEUM PIPELINE SYSTEMS								
462.00	Trans. Plant - Compressor Structures	30-R4	0%	11,546,482	3,277,769	8,268,713	411,433	3.56%	20.1
463.00	Trans. Plant - Meas. & Reg. Structures	30-S1 #	0%	7,705,677.98	2,580,601	5,125,077	232,910	3.02%	22.0
464.00	Trans. Plant - Other Structures	35-R3	0%	129,523	15,641	113,881	3,691	2.85%	30.9
465.00	Trans. Plant - Trans. Pipeline	65-R3	0%	323,598,665	81,152,228	242,446,438	5,005,566	1.55%	48.4
465.11	Intermed. Pipe - Whistler	70-R3	0%	41,593,674	162	41,593,512	594,195	1.43%	70.0
466.00	Trans. Plant - Compressor Equipment	35-R3	0%	60,674,779	13,992,225	46,682,554	1,760,883	2.90%	26.5
467.10	Trans. Plant - Meas. & Reg. Equipment	27-L1	0%	14,488,683	3,296,477	11,192,206	622,364	4.30%	18.0
467.31	Intermed. Pressure - Meas. & Reg. Equipment- Whistler	25-R2.5	0%	311,834	-	311,834	12,473	4.00%	25.0
468.00	Trans. Plant - Communications Equipment	12-R2.5	0%	3,687,558	1,737,270	1,950,289	441,492	11.97%	4.4
472.00	Dist. Systems - Structures	29-L0.5	0%	2,179,427	835,205	1,344,222	66,971	3.07%	20.1
473.00	Dist. Systems - Services	50-R1	0%	163,845,100	23,808,076	140,037,024	3,273,618	2.00%	42.8
474.00	Dist. Systems - Meters/Reg. Installations	22-R2.5	0%	20,941,299	5,313,929	15,627,370	1,205,658	5.76%	13.0
474.02	New Meter Installations	22-SQ	0%	-	-	-		4.55%	
475.00	Dist. Systems - Mains	64-R2	0%	274,328,761	57,495,209	216,833,552	4,092,011	1.49%	53.0
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	7,641,773	2,834,909	4,806,864	332,146	4.35%	14.5
478.10	Dist. Systems - Meters	20-R2.5	0%	13,356,235	3,845,996	9,510,239	847,841	6.35%	11.2
	TOTAL NATURAL GAS & PETROLEUM PIPELINE SYSTEMS			**946,029,472**	**200,185,698**	**745,843,774**	**18,903,252**		
	PLANT, BUILDING AND EQUIPMENT								
482.10	General Plant - Structures (Frame)	20-L0.5	0%	3,844,930	628,300	3,216,629	247,595	6.44%	13.0
482.20	General Plant - Structures (Masonry)	45-R1.5	0%	979,711	19,548	960,163	21,644	2.21%	44.4
482.30	General Plant - Structures (Leased)	20-R0.5	0%	399,301	139,560	259,741	16,596	4.16%	15.7
483.10	General Plant - Computer Hardware	5-SQ	0%	1,793,856	168,150	1,625,706	358,771	20.00%	3.3
483.20	General Plant - Computer Software 12.5%	8-SQ	0%	271,176	50,845	220,331	33,897	12.50%	6.6
483.21	General Plant - Computer Software 20%	5-SQ	0%	12,845	578	12,267	2,569	20.00%	4.8
483.22	General Plant - Computer Software 5.26%	5-SQ	0%	51,323	26,231	25,092	10,265	20.00%	1.0
483.30	General Plant - Office Equipment	15-SQ	0%	651,582	348,827	302,755	43,440	6.67%	4.3
483.40	General Plant - Furniture	20-SQ	0%	166,256	16,533	149,723	8,313	5.00%	18.0
484.00	General Plant - Vehicles	5-L0.5	20%	4,722,292	1,152,458	2,625,376	836,609	17.72%	3.1
485.10	General Plant - Heavy Work Equipment	10-L0.5	15%	321,406	158,552	114,643	18,994	5.91%	6.0
485.20	General Plant - Heavy Mobile Equipment	7-R1.5	10%	857,978	75,701	696,479	126,513	14.75%	5.5
486.00	General Plant - Small Tools/Equipment	20-SQ	0%	6,362,352	2,995,209	3,367,143	318,117	5.00%	10.4
488.10	General Plant - Telephone Equipment	15-SQ	0%	758,960	433,081	325,879	50,598	6.67%	7.1
	TOTAL PLANT, BUILDING AND EQUIPMENT			**21,193,968**	**6,213,573**	**13,901,927**	**2,093,921**		
	INTANGIBLES								
401.01	Franchises and Consents	40-SQ	0%	189,777	61,601	128,175	5,824	3.07%	22.0
402.01	Computer Software - Application 8 Year	8-SQ	0%	15,517,393	5,493,786	10,023,607	1,939,675	12.50%	4.4
402.02	Computer Software - Application 5 Year	5-SQ	0%	1,741,967	1,306,211	435,755	348,394	20.00%	4.9
402.03	Intangible Plant	40-SQ	0%	1,219,037	566,055	652,982	22,907	1.88%	28.5
	TOTAL INTANGIBLES			**18,478,396**	**7,366,053**	**11,112,344**	**2,310,976**		
	TOTAL DEPRECIABLE PLANT			**985,701,836**	**213,765,323**	**770,858,045**	**23,308,149**		

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

SCHEDULE 2A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	LNG PLANT - MT. HAYES ASSETS								
442.00	LNG Plant - Structures	25-SQ	-10%						
443.00	LNG Plant - Equipment	60-SQ	-20%						
448.1	LNG Plant - Piping	40-SQ	-10%						
448.2	LNG Plant- Pre-Treatment	25-SQ	-10%						
448.3	LNG Plant - Liquefaction Equipment	40-SQ	-10%						
448.4	LNG Plant- Send Out Equipment	40-SQ	-10%						
448.5	LNG Plant- Sub-Station and Electrical	40-SQ	-10%						
448.6	LNG Plant- Control Room	15-SQ	-10%						
	TOTAL LNG PLANT - MT. HAYES ASSETS								
	NATURAL GAS & PETROLEUM PIPELINE SYSTEMS								
462.00	Trans. Plant - Compressor Structures	30-R4	-5%	11,546,482	157,552.13	419,771.99	20,884.18	0.18%	20.1
463.00	Trans. Plant - Meas. & Reg. Structures	30-S1	-5%	7,705,677.98	-	385,283.90	17,512.90	0.23%	22.0
464.00	Trans. Plant - Other Structures	35-R3	-5%	129,523	795.66	5,680.47	184.13	0.14%	30.9
465.00	Trans. Plant - Trans. Pipeline	65-R3	-10%	323,598,665	6,006,419.10	26,353,447.44	544,492.72	0.17%	48.4
465.11	Intermed. Pipe - Whistler	70-R3	0%	41,593,674	-	-	-	0.00%	70.0
466.00	Trans. Plant - Compressor Equipment	35-R3	-10%	60,674,779	1,198,962.26	4,868,515.61	183,648.27	0.30%	26.5
467.10	Trans. Plant - Meas. & Reg. Equipment	27-L1	-5%	14,488,683	168,698.02	555,736.15	30,908.57	0.21%	18.0
467.31	Intermed. Pressure - Meas. & Reg. Equipment- Wh	25-R2.5	0%	311,834	-	-	-	0.00%	25.0
468.00	Trans. Plant - Communications Equipment	12-R2.5	-5%	3,687,558	-	184,377.92	81,583.15	2.21%	2.3
472.00	Dist. Systems - Structures	29-L0.5	-5%	2,179,427	36,419.19	72,552.17	3,614.96	0.17%	20.1
473.00	Dist. Systems - Services	50-R1	-50%	163,845,100	10,271,525.69	71,651,024.51	1,674,872.01	1.02%	42.8
474.00	Dist. Systems - Meters/Reg. Installations	22-R2.5	-10%	20,941,299	-	2,094,129.87	161,086.91	0.77%	13.0
475.00	Dist. Systems - Mains	64-R2	-20%	274,328,761	9,872,890.79	44,992,861.36	849,082.12	0.31%	53.0
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	7,641,773	-	-	0.00	0.00%	14.5
478.10	Dist. Systems - Meters	20-R2.5	-5%	13,356,235	-	667,811.75	59,839.76	0.45%	11.2
	TOTAL NATURAL GAS & PETROLEUM PIPELINE SYSTEMS			**946,029,472**	**27,713,262.84**	**152,251,193**	**3,627,709.68**		
	TOTAL			**946,029,472**	**27,713,263**	**152,251,193**	**3,627,710**		

FORTISBC (WHISTLER) INC.

SCHEDULE 3. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO LIFE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	NATURAL GAS & PETROLEUM PIPELINE SYSTEMS								
472.00	Dist. Systems - Structures	29-L0.5	0%	1,720	123	1,597	58	3.37%	27.5
473.00	Dist. Systems - Services	50-R1	0%	3,673,803	366,721	3,307,082	75,681	2.06%	43.7
474.00	Dist. Systems- Meters/ Reg. Installations	22-R2.5	0%	1,348,578	291,914	1,056,664	69,124	5.13%	15.3
474.02	New Meter Installations	22-SQ	0%	0	0	0		4.55%	0.0
475.00	Dist. Systems - Mains	64-R2	0%	8,533,097	1,345,406	7,187,690	128,503	1.51%	55.9
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	579,933	12,340	567,593	22,381	3.86%	25.4
477.20	Dist. Systems - Telemetry	27-R1.5	0%	2,256	0	2,256	84	3.72%	26.9
478.10	Dist. Systems - Meters	20-R2.5	0%	443,017	94,817	348,200	28,610	6.46%	12.2
	TOTAL NATURAL GAS & PETROLEUM PIPELINE SYSTEMS			**14,582,403**	**2,111,321**	**12,471,082 0**	**324,441**		
	PLANT, BUILDING AND EQUIPMENT								
482.10	General Plant - Structures (Frame)	20-L0.5	0%	8,128	3,567	4,560	374	4.60%	12.2
483.30	General Plant - Office Equipment	15-SQ	0%	7,661	4,589	3,072	510	6.66%	3.0
484.00	General Plant - Vehicles	5-L0.5	20%	154,309	36,274	87,173	20,284	13.15%	4.3
485.10	General Plant - Heavy Work Equipment	10-L0.5	15%	95,256	63,474	17,493	3,025	3.18%	5.8
486.00	General Plant - Small Tools/Equipment	20-SQ	0%	186,120	106,201	79,919	9,305	5.00%	8.6
488.10	General Plant - Telephone Equipment	15-SQ	0%	15,627	9,398	6,229	1,042	6.67%	3.0
	TOTAL PLANT, BUILDING AND EQUIPMENT			**467,100**	**223,503**	**198,446 0**	**34,540**		
	INTANGIBLES								
401.01	Franchises and Consents	40-SQ	0%	8,239	1,808	6,431	357	4.33%	18.0
	TOTAL INTANGIBLES			**8,239**	**1,808**	**6,431 0**	**357**		
	TOTAL DEPRECIABLE PLANT			**15,099,770**	**2,865,241**	**14,026,774**	**414,666**		

FORTISBC ENERGY (WHISTLER) INC.

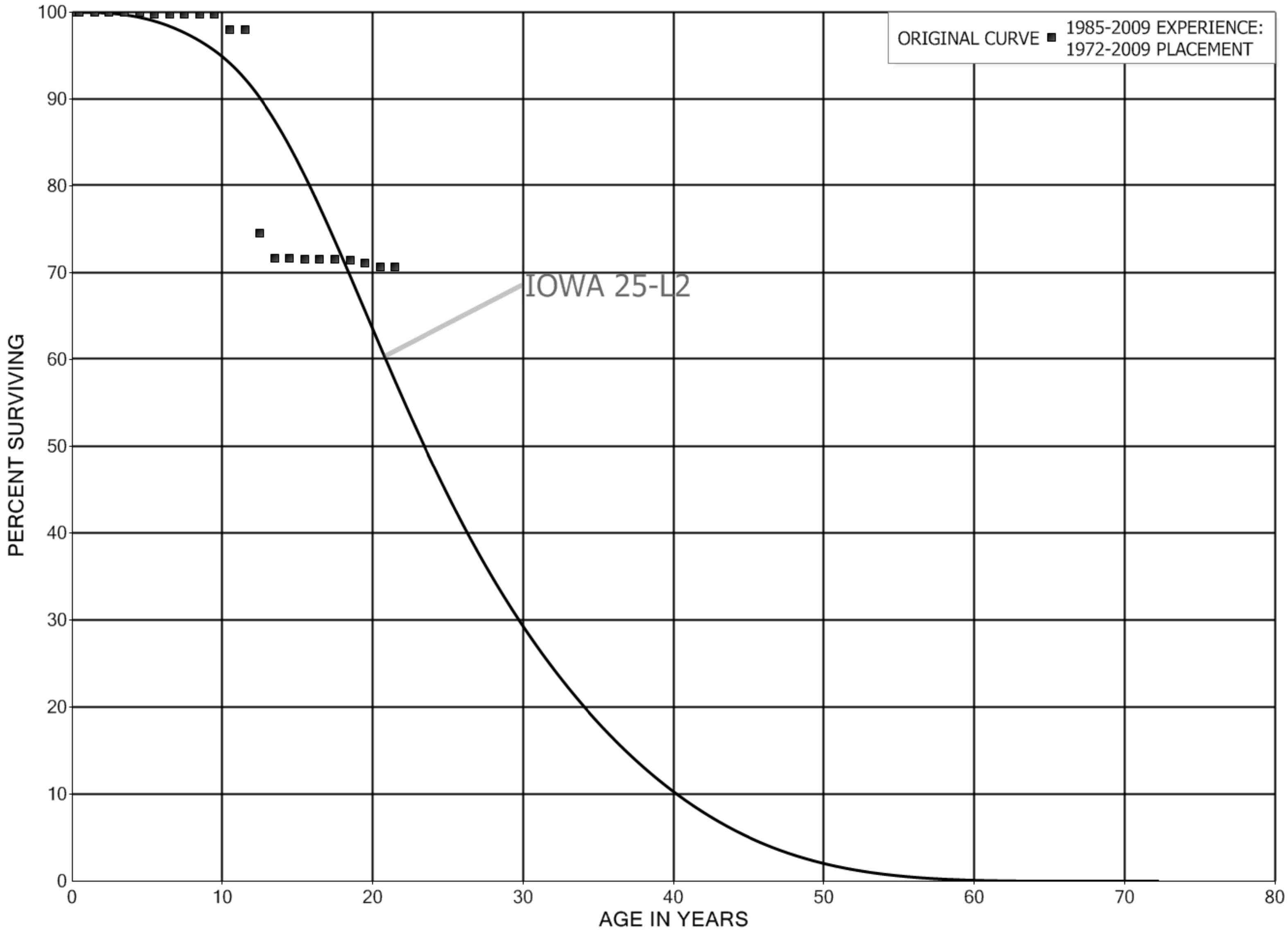
SCHEDULE 3A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009

DEPRECIATION RELATED TO NET SALVAGE

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	NATURAL GAS & PETROLEUM PIPELINE SYSTEMS								
472.00	Dist. Systems - Structures	29-L0.5	-5%	1,720	7.54	78.45	2.85	0.17%	27.5
473.00	Dist. Systems - Services	50-R1	-50%	3,673,803	226,725.29	1,610,176.04	36,846.13	1.00%	43.7
474.00	Dist. Systems- Meters/ Reg. Installations	22-R2.5	-10%	1,348,578	-	134,857.80	8,814.24	0.65%	15.3
475.00	Dist. Systems - Mains	64-R2	-20%	8,533,097	292,065.80	1,414,553.58	25,291.50	0.30%	55.9
477.10	Dist. Systems - Meas. & Reg. Additions	26-R2	0%	579,933	-	-		0.00%	25.4
477.20	Dist. Systems - Telemetry	27-R1.5	0%	2,256	-	-		0.00%	26.9
478.10	Dist. Systems - Meters	20-R2.5	-5%	443,017	-	22,150.86	1,815.64	0.41%	12.2
	Total NATURAL GAS & PETROLEUM PIPELINE SYSTEMS			**14,582,403**	**518,798.63**	**3,181,816.72**	**72,770**		
						-			
	TOTAL DEPRECIABLE PLANT			**14,582,403**	**518,799**	**1,610,254**	**36,849**		

PART IV. SERVICE LIFE STATISTICS

FORTISBC ENERGY INC.
ACCOUNT 442.00 - LNG GAS STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



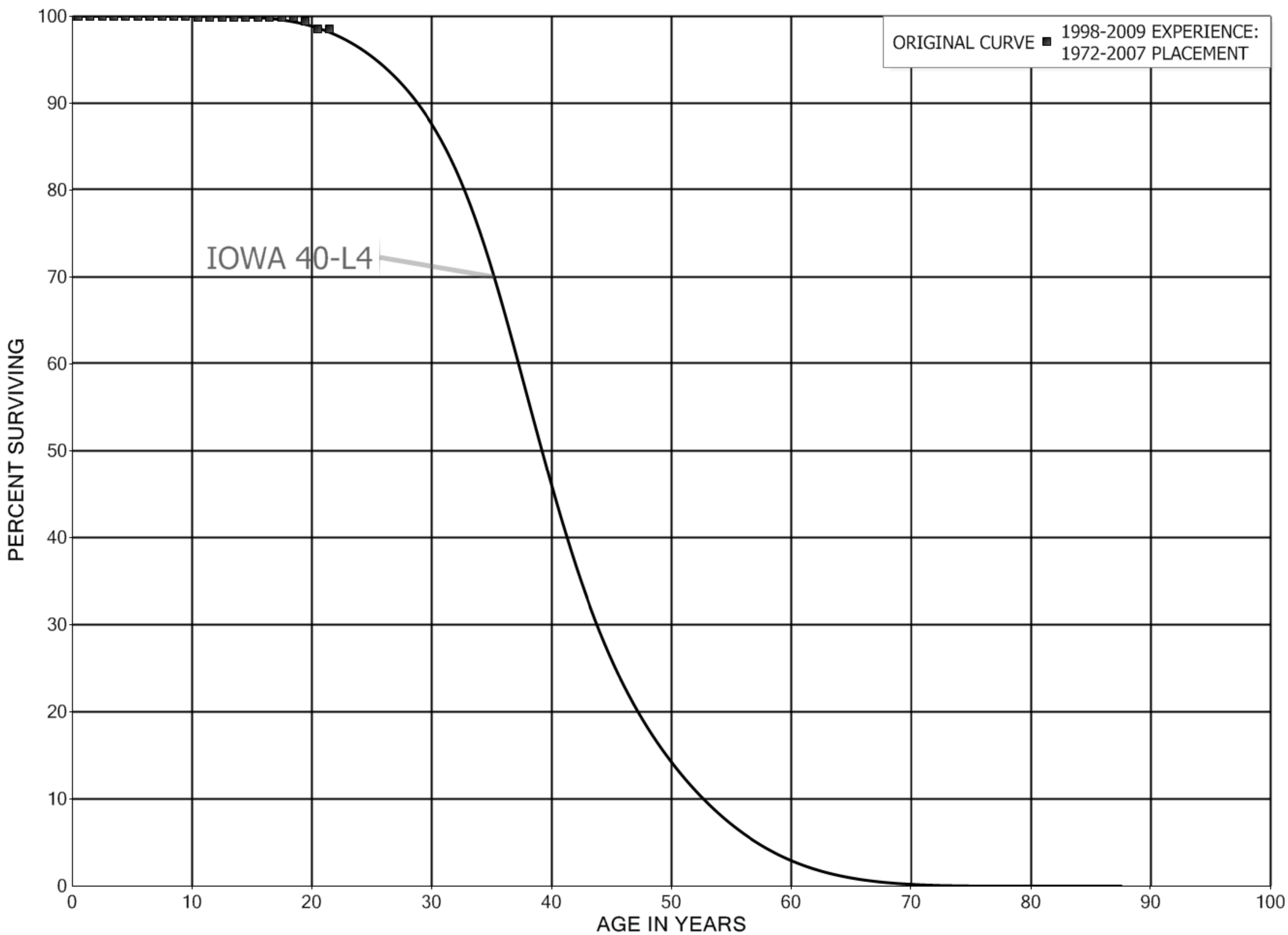
FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009
ACCOUNT 442.00 - LNG GAS STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2009 EXPERIENCE BAND 1985-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,578,945		0.0000	1.0000	100.00
0.5	5,578,945		0.0000	1.0000	100.00
1.5	5,638,454		0.0000	1.0000	100.00
2.5	5,367,852		0.0000	1.0000	100.00
3.5	5,354,240		0.0000	1.0000	100.00
4.5	4,565,782	11,458	0.0025	0.9975	100.00
5.5	4,537,328		0.0000	1.0000	99.75
6.5	3,837,445		0.0000	1.0000	99.75
7.5	3,800,911		0.0000	1.0000	99.75
8.5	3,706,092	1,000	0.0003	0.9997	99.75
9.5	3,386,343	61,358	0.0181	0.9819	99.72
10.5	3,191,092		0.0000	1.0000	97.92
11.5	2,794,346	669,121	0.2395	0.7605	97.92
12.5	1,929,203	74,954	0.0389	0.9611	74.47
13.5	1,811,469		0.0000	1.0000	71.58
14.5	1,678,888	2,477	0.0015	0.9985	71.58
15.5	1,591,849		0.0000	1.0000	71.47
16.5	1,583,755		0.0000	1.0000	71.47
17.5	1,473,328	1,959	0.0013	0.9987	71.47
18.5	1,469,444	6,000	0.0041	0.9959	71.38
19.5	1,463,444	10,373	0.0071	0.9929	71.08
20.5	1,453,071		0.0000	1.0000	70.58
21.5					

FORTISBC ENERGY INC.
ACCOUNT 443.00 - LNG GAS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

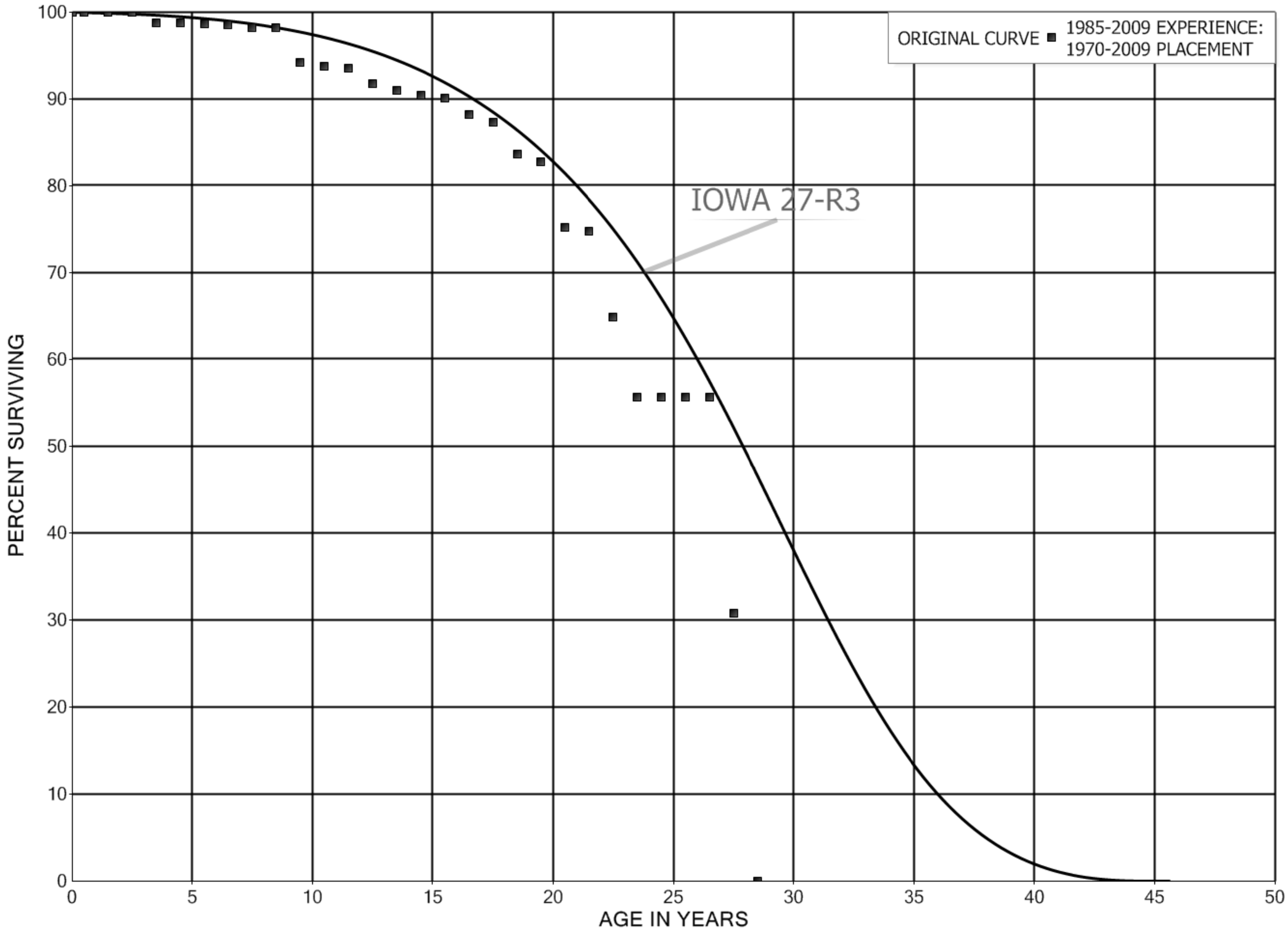
ACCOUNT 443.00 - LNG GAS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2007 EXPERIENCE BAND 1998-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,772,522		0.0000	1.0000	100.00
0.5	6,957,126		0.0000	1.0000	100.00
1.5	7,350,598		0.0000	1.0000	100.00
2.5	7,350,338		0.0000	1.0000	100.00
3.5	7,298,840		0.0000	1.0000	100.00
4.5	7,374,000	1,000	0.0001	0.9999	100.00
5.5	7,175,955		0.0000	1.0000	99.99
6.5	7,022,362		0.0000	1.0000	99.99
7.5	1,718,292		0.0000	1.0000	99.99
8.5	1,615,997		0.0000	1.0000	99.99
9.5	10,586,096	12,708	0.0012	0.9988	99.99
10.5	9,950,987		0.0000	1.0000	99.87
11.5	9,848,562		0.0000	1.0000	99.87
12.5	9,663,958		0.0000	1.0000	99.87
13.5	9,270,486		0.0000	1.0000	99.87
14.5	9,270,486		0.0000	1.0000	99.87
15.5	9,270,486	1,734	0.0002	0.9998	99.87
16.5	9,206,300		0.0000	1.0000	99.85
17.5	9,206,300		0.0000	1.0000	99.85
18.5	9,176,353	44,685	0.0049	0.9951	99.85
19.5	9,131,668	79,648	0.0087	0.9913	99.36
20.5	9,052,020		0.0000	1.0000	98.49
21.5					
22.5					
23.5					
24.5					
25.5	27,340	27,340	1.0000		
26.5					

FORTISBC ENERGY INC.
ACCOUNT 449.00 - LNG GAS OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

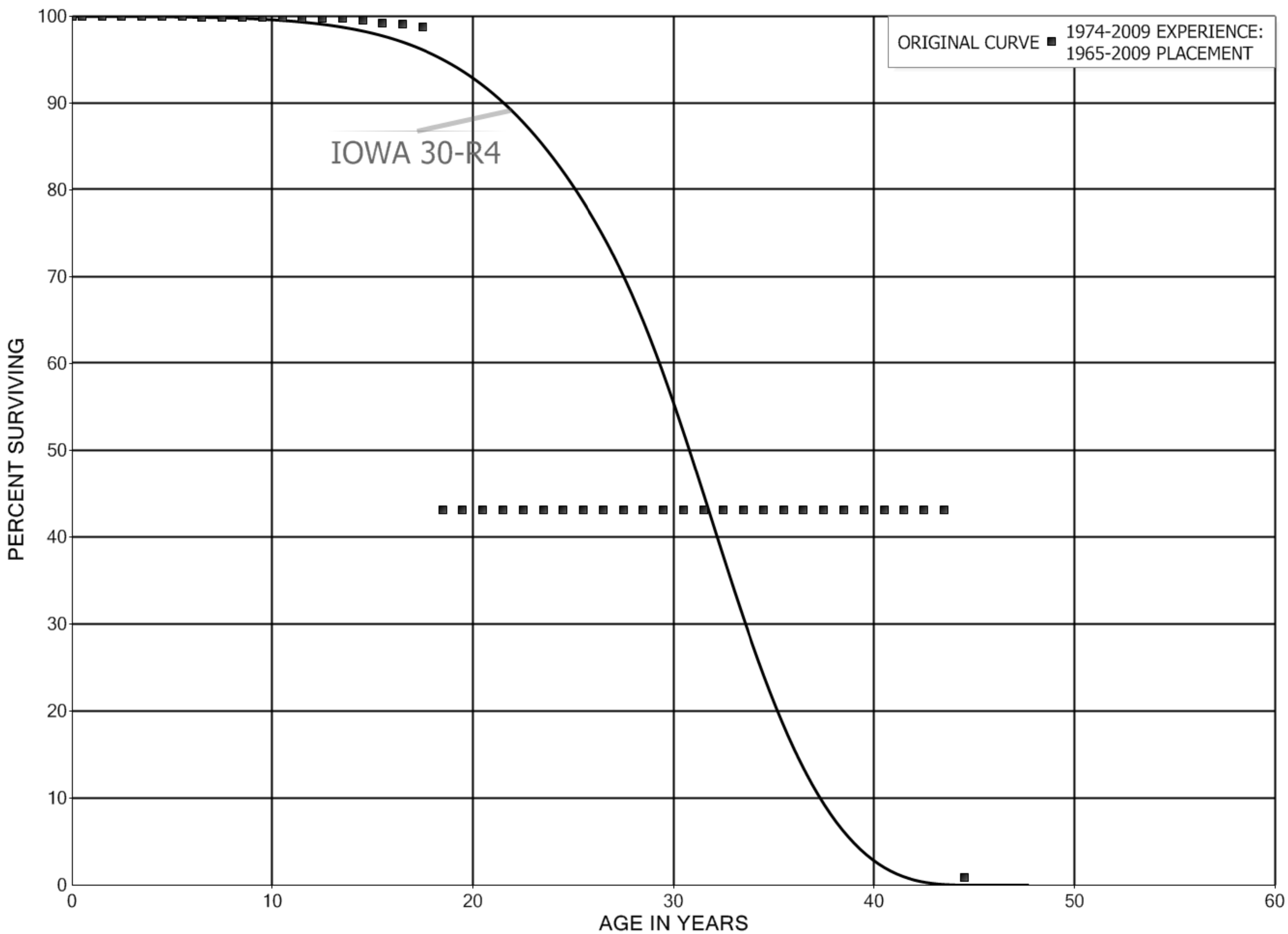
ACCOUNT 449.00 - LNG GAS OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2009 EXPERIENCE BAND 1985-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,302,090	500	0.0000	1.0000	100.00
0.5	23,150,956		0.0000	1.0000	100.00
1.5	20,288,100	1	0.0000	1.0000	100.00
2.5	19,929,048	258,133	0.0130	0.9870	100.00
3.5	19,412,375	48	0.0000	1.0000	98.70
4.5	19,216,251	10,802	0.0006	0.9994	98.70
5.5	19,239,051	21,004	0.0011	0.9989	98.65
6.5	17,418,198	56,589	0.0032	0.9968	98.54
7.5	17,004,615	9,223	0.0005	0.9995	98.22
8.5	16,974,021	698,665	0.0412	0.9588	98.17
9.5	15,310,509	70,887	0.0046	0.9954	94.13
10.5	14,590,585	25,930	0.0018	0.9982	93.69
11.5	14,549,895	286,493	0.0197	0.9803	93.52
12.5	14,414,063	123,449	0.0086	0.9914	91.68
13.5	13,543,172	67,845	0.0050	0.9950	90.90
14.5	10,670,983	41,927	0.0039	0.9961	90.44
15.5	10,433,409	215,295	0.0206	0.9794	90.09
16.5	7,881,222	85,676	0.0109	0.9891	88.23
17.5	7,232,619	300,308	0.0415	0.9585	87.27
18.5	6,377,848	71,537	0.0112	0.9888	83.64
19.5	6,306,311	578,265	0.0917	0.9083	82.71
20.5	5,728,047	27,751	0.0048	0.9952	75.12
21.5	163,359	21,715	0.1329	0.8671	74.76
22.5	141,644	20,000	0.1412	0.8588	64.82
23.5	121,644		0.0000	1.0000	55.67
24.5	121,644		0.0000	1.0000	55.67
25.5	121,644	9	0.0001	0.9999	55.67
26.5	121,635	54,471	0.4478	0.5522	55.66
27.5	67,164	67,164	1.0000		30.74
28.5					

FORTISBC ENERGY INC.
ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2009 EXPERIENCE BAND 1974-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,880,933		0.0000	1.0000	100.00
0.5	15,042,127		0.0000	1.0000	100.00
1.5	14,994,698	1,338	0.0001	0.9999	100.00
2.5	14,943,448		0.0000	1.0000	99.99
3.5	14,916,059	1,225	0.0001	0.9999	99.99
4.5	14,914,834	7,893	0.0005	0.9995	99.98
5.5	14,767,406	6,379	0.0004	0.9996	99.93
6.5	14,660,748	2,414	0.0002	0.9998	99.89
7.5	13,535,660	659	0.0000	1.0000	99.87
8.5	12,777,804	3,363	0.0003	0.9997	99.87
9.5	9,056,642	3,380	0.0004	0.9996	99.84
10.5	9,028,549	6,438	0.0007	0.9993	99.80
11.5	8,941,122		0.0000	1.0000	99.73
12.5	8,639,178	1,162	0.0001	0.9999	99.73
13.5	8,203,542	15,868	0.0019	0.9981	99.72
14.5	3,563,046	14,083	0.0040	0.9960	99.52
15.5	2,067,185	461	0.0002	0.9998	99.13
16.5	890,462	3,140	0.0035	0.9965	99.11
17.5	706,671	398,159	0.5634	0.4366	98.76
18.5	295,553		0.0000	1.0000	43.12
19.5	264,255		0.0000	1.0000	43.12
20.5	261,696		0.0000	1.0000	43.12
21.5	259,140		0.0000	1.0000	43.12
22.5	259,140		0.0000	1.0000	43.12
23.5	259,140		0.0000	1.0000	43.12
24.5	259,140		0.0000	1.0000	43.12
25.5	258,244		0.0000	1.0000	43.12
26.5	258,244		0.0000	1.0000	43.12
27.5	256,998		0.0000	1.0000	43.12
28.5	256,998		0.0000	1.0000	43.12
29.5	256,384		0.0000	1.0000	43.12
30.5	255,350		0.0000	1.0000	43.12
31.5	249,433		0.0000	1.0000	43.12
32.5	249,366		0.0000	1.0000	43.12
33.5	249,366		0.0000	1.0000	43.12
34.5	243,208		0.0000	1.0000	43.12
35.5	243,208		0.0000	1.0000	43.12
36.5	27,807		0.0000	1.0000	43.12
37.5	27,807		0.0000	1.0000	43.12
38.5	27,807		0.0000	1.0000	43.12

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

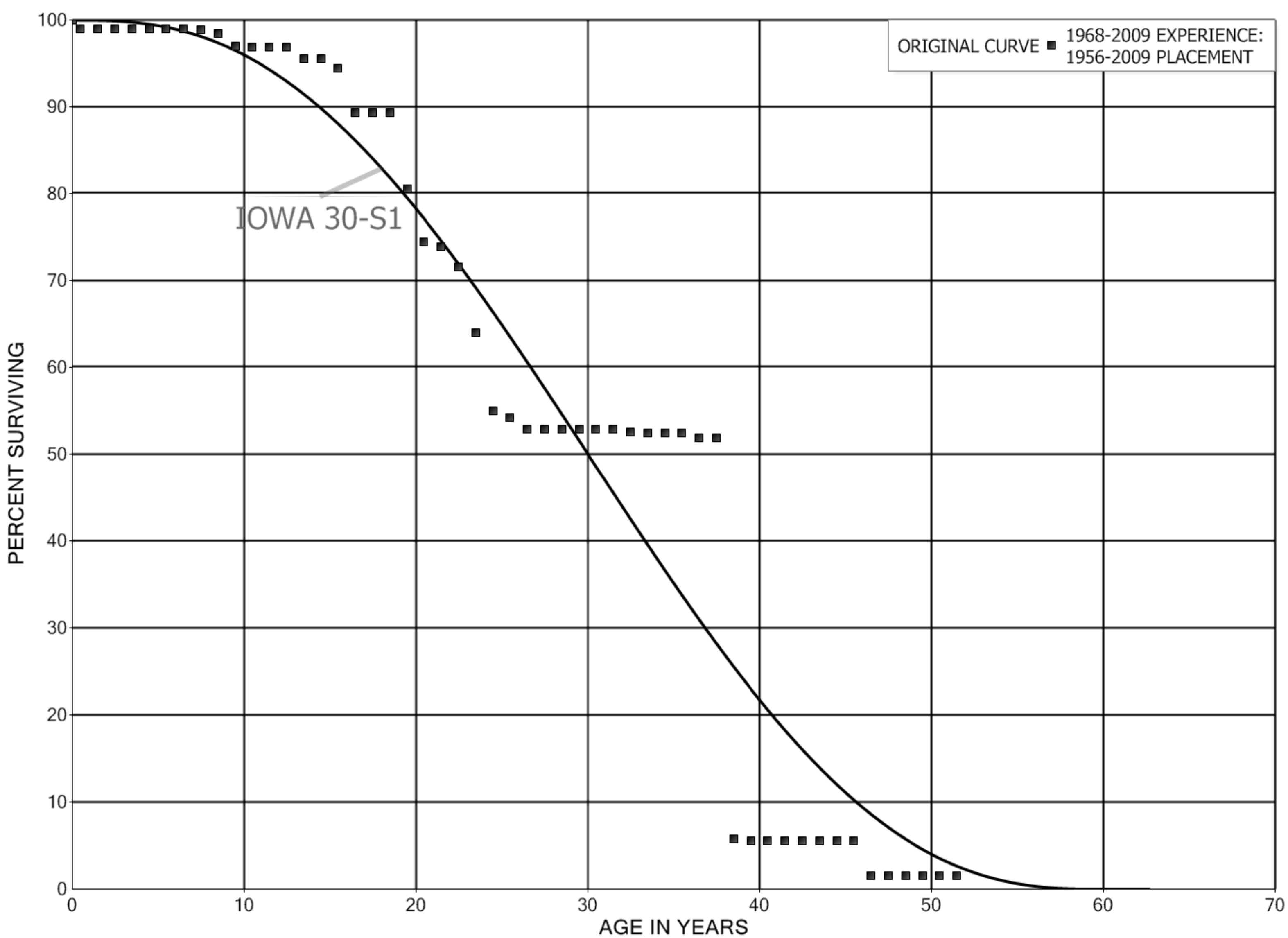
ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2009 EXPERIENCE BAND 1974-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	27,807		0.0000	1.0000	43.12
40.5	27,807		0.0000	1.0000	43.12
41.5	27,807		0.0000	1.0000	43.12
42.5	27,807		0.0000	1.0000	43.12
43.5	27,807	27,247	0.9799	0.0201	43.12
44.5					

FORTISBC ENERGY INC.
ACCOUNT 463.00 - TRANS. PLANT - MEAS. & REG. STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 463.00 - TRANS. PLANT - MEAS. & REG. STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2009 EXPERIENCE BAND 1968-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,387,575	53,753	0.0100	0.9900	100.00
0.5	5,144,533	3	0.0000	1.0000	99.00
1.5	5,131,891	23	0.0000	1.0000	99.00
2.5	5,113,792	142	0.0000	1.0000	99.00
3.5	5,036,523	167	0.0000	1.0000	99.00
4.5	4,944,474	617	0.0001	0.9999	99.00
5.5	4,577,594	244	0.0001	0.9999	98.98
6.5	4,374,403	6,386	0.0015	0.9985	98.98
7.5	3,594,074	17,727	0.0049	0.9951	98.83
8.5	3,471,486	48,726	0.0140	0.9860	98.35
9.5	3,061,597	4,013	0.0013	0.9987	96.97
10.5	2,911,752	544	0.0002	0.9998	96.84
11.5	2,896,954	437	0.0002	0.9998	96.82
12.5	2,750,306	36,190	0.0132	0.9868	96.81
13.5	2,368,162	955	0.0004	0.9996	95.53
14.5	1,894,769	22,233	0.0117	0.9883	95.49
15.5	1,801,340	97,354	0.0540	0.9460	94.37
16.5	1,529,930	113	0.0001	0.9999	89.27
17.5	1,268,163	59	0.0000	1.0000	89.27
18.5	472,294	46,351	0.0981	0.9019	89.26
19.5	420,694	31,956	0.0760	0.9240	80.50
20.5	386,836	2,962	0.0077	0.9923	74.39
21.5	194,992	6,227	0.0319	0.9681	73.82
22.5	179,354	18,950	0.1057	0.8943	71.46
23.5	159,039	22,385	0.1408	0.8592	63.91
24.5	133,611	1,851	0.0139	0.9861	54.91
25.5	120,840	3,000	0.0248	0.9752	54.15
26.5	117,840		0.0000	1.0000	52.81
27.5	116,593		0.0000	1.0000	52.81
28.5	116,593		0.0000	1.0000	52.81
29.5	112,012		0.0000	1.0000	52.81
30.5	112,012		0.0000	1.0000	52.81
31.5	112,012	622	0.0056	0.9944	52.81
32.5	111,390	322	0.0029	0.9971	52.52
33.5	111,068		0.0000	1.0000	52.36
34.5	105,209		0.0000	1.0000	52.36
35.5	92,672	1,000	0.0108	0.9892	52.36
36.5	91,672		0.0000	1.0000	51.80
37.5	60,975	54,267	0.8900	0.1100	51.80
38.5	6,708	230	0.0343	0.9657	5.70

FORTISBC ENERGY INC.

RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

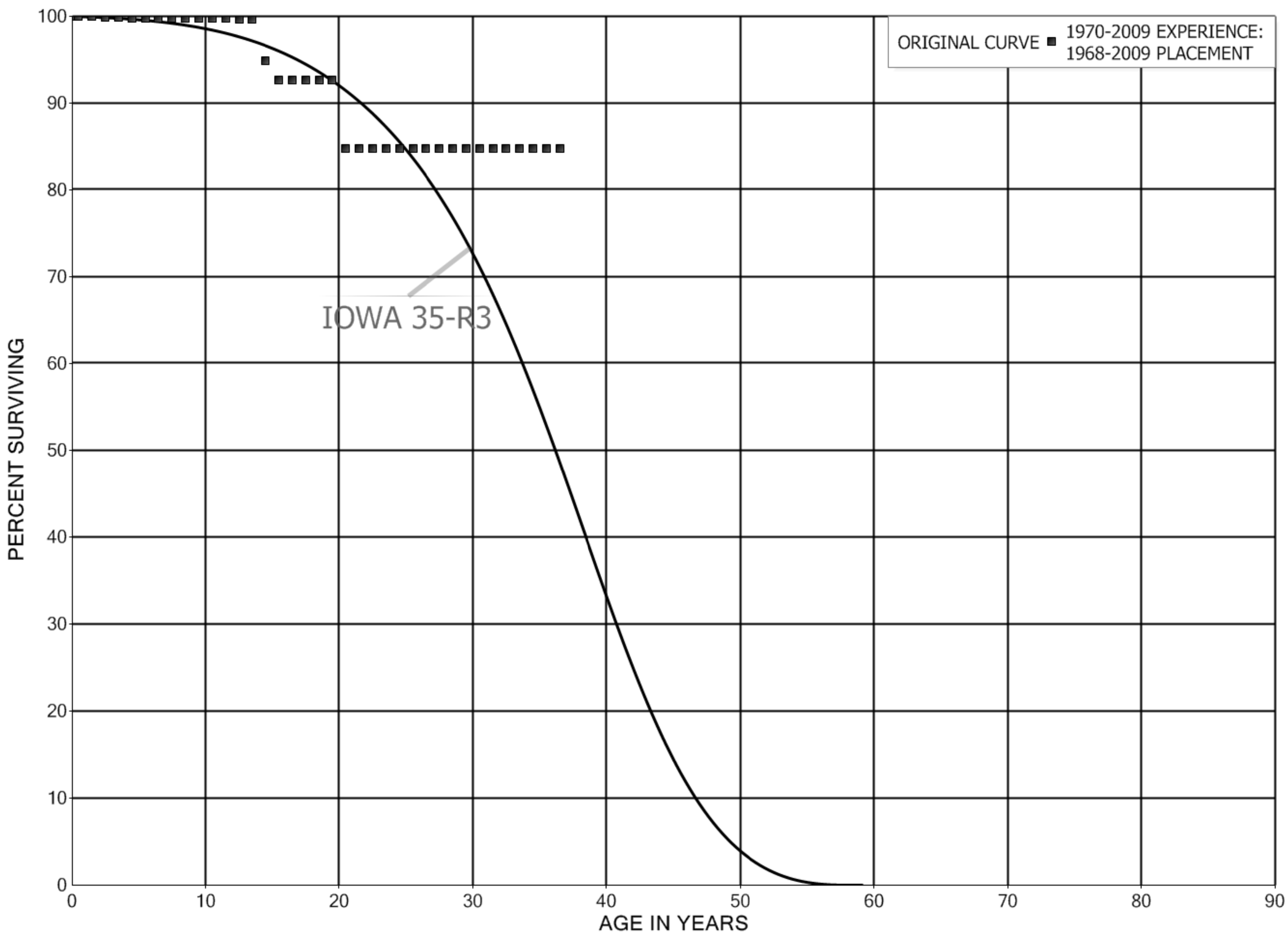
ACCOUNT 463.00 - TRANS. PLANT - MEAS. & REG. STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2009 EXPERIENCE BAND 1968-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,478		0.0000	1.0000	5.50
40.5	6,478		0.0000	1.0000	5.50
41.5	6,478		0.0000	1.0000	5.50
42.5	6,478		0.0000	1.0000	5.50
43.5	6,478		0.0000	1.0000	5.50
44.5	6,478		0.0000	1.0000	5.50
45.5	6,478	4,697	0.7251	0.2749	5.50
46.5	1,781		0.0000	1.0000	1.51
47.5	1,781		0.0000	1.0000	1.51
48.5	1,781		0.0000	1.0000	1.51
49.5	1,781		0.0000	1.0000	1.51
50.5	1,781		0.0000	1.0000	1.51
51.5					

FORTISBC ENERGY INC.
ACCOUNT 464.00 - TRANS. PLANT - OTHER STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

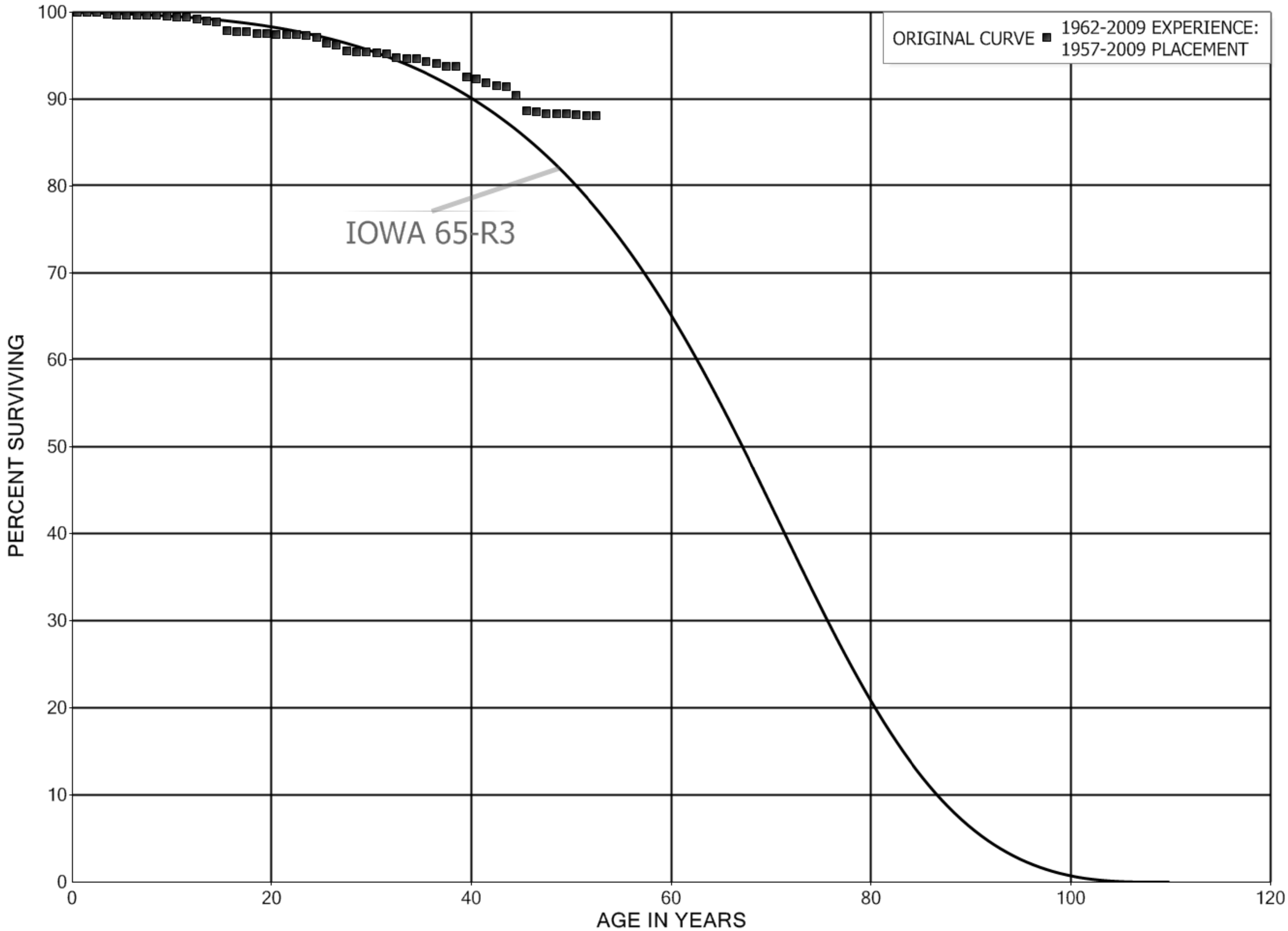
ACCOUNT 464.00 - TRANS. PLANT - OTHER STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2009 EXPERIENCE BAND 1970-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,864,961		0.0000	1.0000	100.00
0.5	5,849,796		0.0000	1.0000	100.00
1.5	5,965,248	7,358	0.0012	0.9988	100.00
2.5	5,853,537	4,055	0.0007	0.9993	99.88
3.5	5,613,273	7,453	0.0013	0.9987	99.81
4.5	5,411,104		0.0000	1.0000	99.67
5.5	4,889,471		0.0000	1.0000	99.67
6.5	4,878,642		0.0000	1.0000	99.67
7.5	4,340,935		0.0000	1.0000	99.67
8.5	507,646		0.0000	1.0000	99.67
9.5	402,221		0.0000	1.0000	99.67
10.5	262,885		0.0000	1.0000	99.67
11.5	259,875	70	0.0003	0.9997	99.67
12.5	242,792		0.0000	1.0000	99.65
13.5	165,909	8,017	0.0483	0.9517	99.65
14.5	157,326	3,713	0.0236	0.9764	94.83
15.5	109,871		0.0000	1.0000	92.59
16.5	109,871		0.0000	1.0000	92.59
17.5	109,871		0.0000	1.0000	92.59
18.5	83,740		0.0000	1.0000	92.59
19.5	79,563	6,746	0.0848	0.9152	92.59
20.5	67,570		0.0000	1.0000	84.74
21.5	54,672		0.0000	1.0000	84.74
22.5	37,043		0.0000	1.0000	84.74
23.5	37,043		0.0000	1.0000	84.74
24.5	37,043		0.0000	1.0000	84.74
25.5	35,848		0.0000	1.0000	84.74
26.5	26,979		0.0000	1.0000	84.74
27.5	26,979		0.0000	1.0000	84.74
28.5	26,979		0.0000	1.0000	84.74
29.5	26,979		0.0000	1.0000	84.74
30.5	16,153		0.0000	1.0000	84.74
31.5	9,838		0.0000	1.0000	84.74
32.5	9,838		0.0000	1.0000	84.74
33.5	9,838		0.0000	1.0000	84.74
34.5	7,845		0.0000	1.0000	84.74
35.5	7,845		0.0000	1.0000	84.74
36.5					

FORTISBC ENERGY INC.
ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 465.00 -TRANS. PLANT - TRANS. PIPELINE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1962-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	707,603,274	120,950	0.0002	0.9998	100.00
0.5	702,070,242	240,793	0.0003	0.9997	99.98
1.5	697,547,193	211,413	0.0003	0.9997	99.95
2.5	694,457,816	1,460,744	0.0021	0.9979	99.92
3.5	696,526,748	336,937	0.0005	0.9995	99.71
4.5	687,121,484	38,596	0.0001	0.9999	99.66
5.5	674,132,699	68,177	0.0001	0.9999	99.65
6.5	656,812,279	235,985	0.0004	0.9996	99.64
7.5	633,236,950	232,832	0.0004	0.9996	99.61
8.5	587,567,670	533,029	0.0009	0.9991	99.57
9.5	268,043,555	143,272	0.0005	0.9995	99.48
10.5	255,624,884	133,324	0.0005	0.9995	99.43
11.5	239,074,503	563,904	0.0024	0.9976	99.38
12.5	228,796,867	581,312	0.0025	0.9975	99.14
13.5	215,645,823	224,700	0.0010	0.9990	98.89
14.5	182,295,914	1,743,223	0.0096	0.9904	98.79
15.5	177,630,416	119,753	0.0007	0.9993	97.84
16.5	171,463,842	100,429	0.0006	0.9994	97.78
17.5	116,460,873	198,990	0.0017	0.9983	97.72
18.5	112,844,081	117,708	0.0010	0.9990	97.55
19.5	106,069,781	42,544	0.0004	0.9996	97.45
20.5	105,328,673	14,452	0.0001	0.9999	97.41
21.5	64,164,625	15,329	0.0002	0.9998	97.40
22.5	62,262,948	92,276	0.0015	0.9985	97.37
23.5	58,458,838	94,207	0.0016	0.9984	97.23
24.5	57,286,570	419,671	0.0073	0.9927	97.07
25.5	56,382,612	97,195	0.0017	0.9983	96.36
26.5	55,833,033	388,747	0.0070	0.9930	96.20
27.5	54,755,762	44,757	0.0008	0.9992	95.53
28.5	53,329,195	32,232	0.0006	0.9994	95.45
29.5	52,544,566	83,697	0.0016	0.9984	95.39
30.5	52,334,373	14,892	0.0003	0.9997	95.24
31.5	51,968,989	270,170	0.0052	0.9948	95.21
32.5	51,302,919	52,712	0.0010	0.9990	94.72
33.5	33,018,290	16,491	0.0005	0.9995	94.62
34.5	32,937,739	82,737	0.0025	0.9975	94.57
35.5	32,822,299	83,701	0.0026	0.9974	94.33
36.5	32,329,142	118,234	0.0037	0.9963	94.09
37.5	24,201,433		0.0000	1.0000	93.75
38.5	21,808,724	295,708	0.0136	0.9864	93.75

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

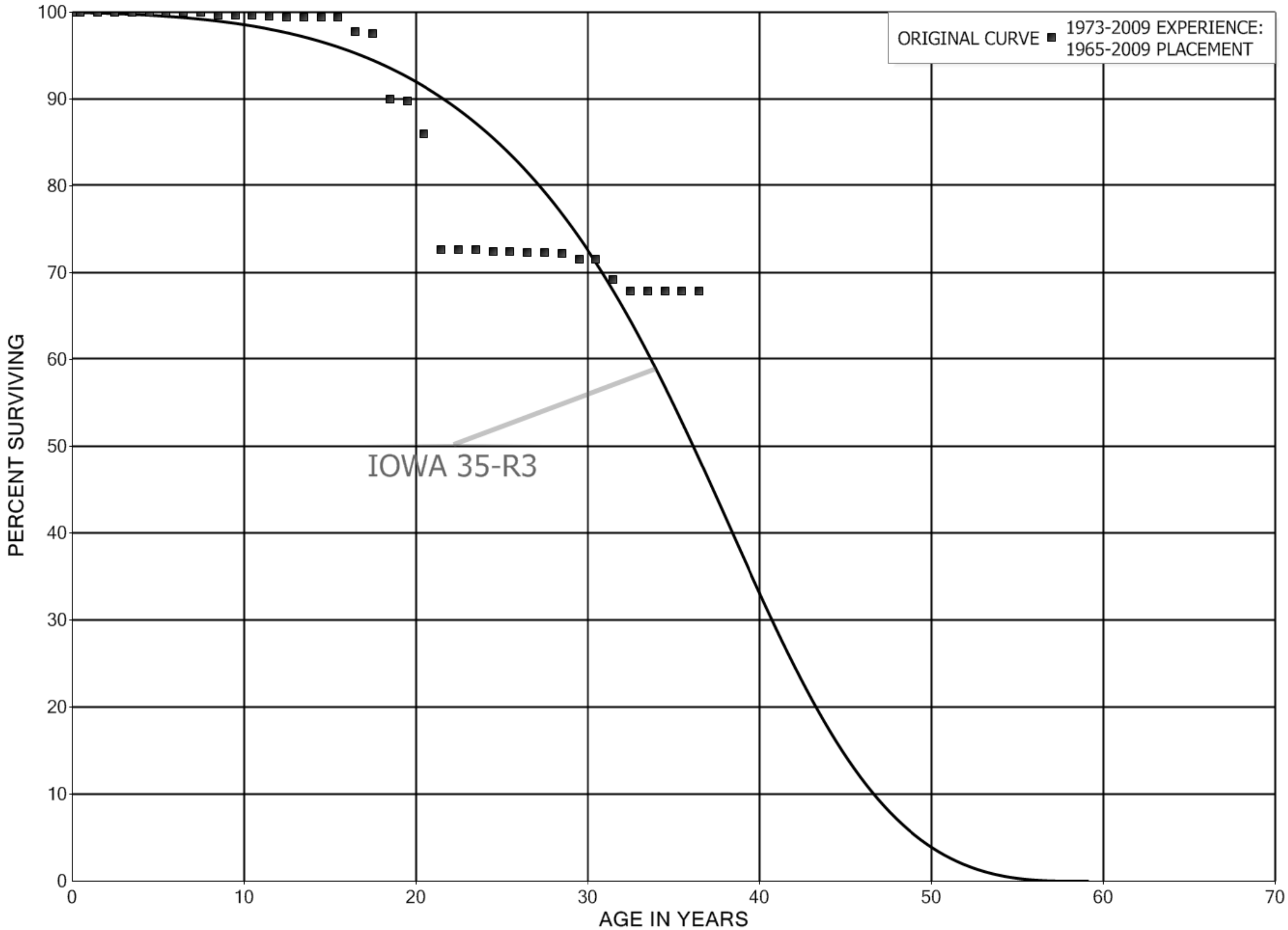
ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1962-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	21,147,630	34,404	0.0016	0.9984	92.48
40.5	19,321,714	98,214	0.0051	0.9949	92.33
41.5	18,454,391	62,472	0.0034	0.9966	91.86
42.5	17,869,986	30,563	0.0017	0.9983	91.55
43.5	17,571,427	200,880	0.0114	0.9886	91.39
44.5	17,370,547	327,084	0.0188	0.9812	90.35
45.5	16,981,953	18,507	0.0011	0.9989	88.65
46.5	16,869,578	49,971	0.0030	0.9970	88.55
47.5	14,390,340	5,119	0.0004	0.9996	88.29
48.5	14,251,953		0.0000	1.0000	88.26
49.5	14,234,345	16,837	0.0012	0.9988	88.26
50.5	12,829,026	10,775	0.0008	0.9992	88.15
51.5	14,800		0.0000	1.0000	88.08
52.5					

FORTISBC ENERGY INC.
ACCOUNT 466.00 - TRANS. PLANT - COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

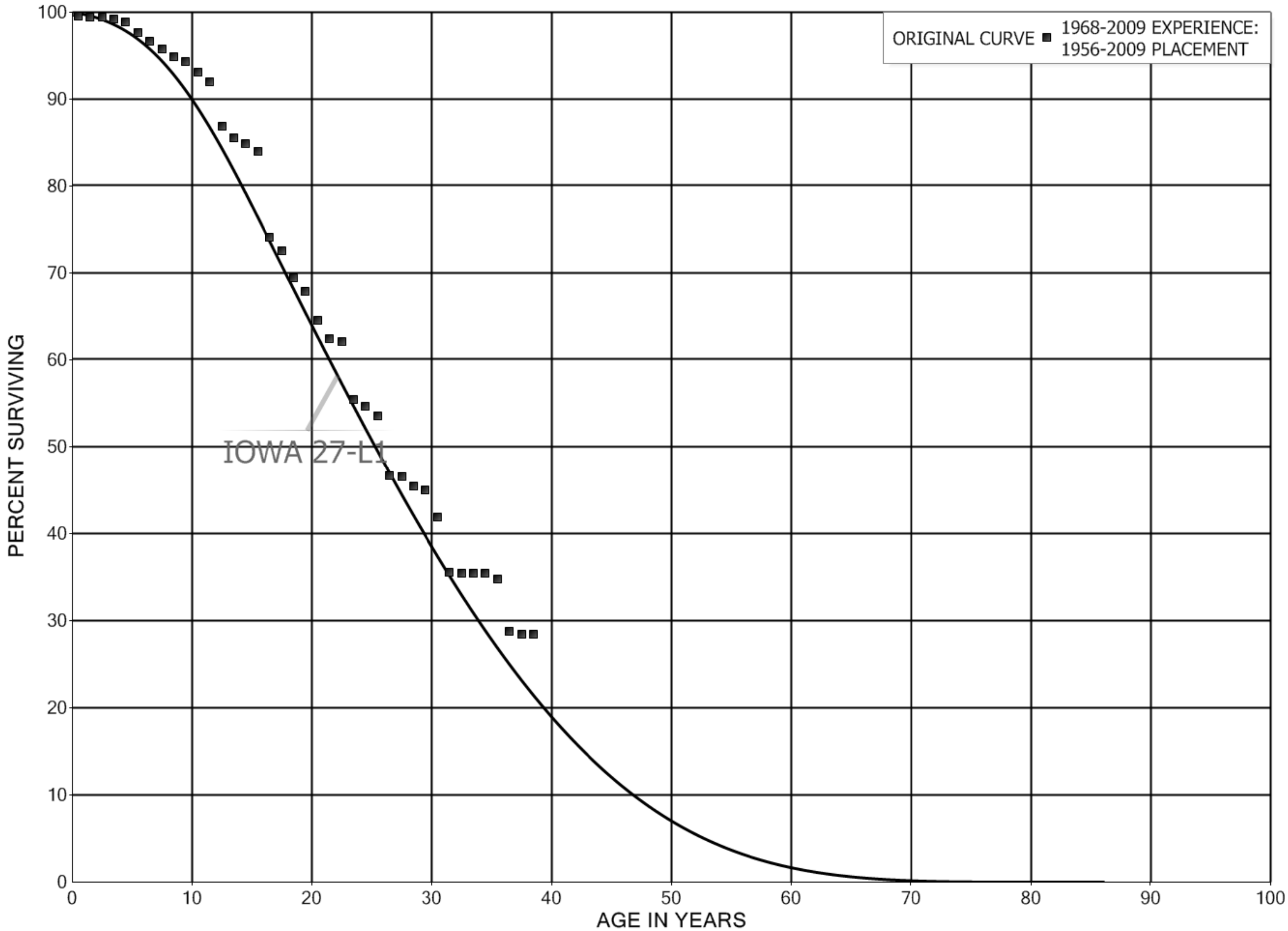
ACCOUNT 466.00 - TRANS. PLANT - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2009 EXPERIENCE BAND 1973-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	108,156,692	35	0.0000	1.0000	100.00
0.5	107,981,849	556	0.0000	1.0000	100.00
1.5	107,679,533	758	0.0000	1.0000	100.00
2.5	107,667,569	2,978	0.0000	1.0000	100.00
3.5	107,653,271	1,513	0.0000	1.0000	100.00
4.5	107,409,052	16,949	0.0002	0.9998	99.99
5.5	105,019,003	23,569	0.0002	0.9998	99.98
6.5	104,210,418	48,288	0.0005	0.9995	99.96
7.5	98,024,429	260,667	0.0027	0.9973	99.91
8.5	91,742,733	62,334	0.0007	0.9993	99.64
9.5	40,870,297	5,855	0.0001	0.9999	99.58
10.5	40,694,660	41,588	0.0010	0.9990	99.56
11.5	40,351,123	11,150	0.0003	0.9997	99.46
12.5	38,013,855	19,310	0.0005	0.9995	99.43
13.5	36,563,668	6,869	0.0002	0.9998	99.38
14.5	31,852,179	3,876	0.0001	0.9999	99.36
15.5	10,817,691	171,537	0.0159	0.9841	99.35
16.5	5,889,256	17,640	0.0030	0.9970	97.78
17.5	3,708,896	284,588	0.0767	0.9233	97.48
18.5	3,301,026	12,182	0.0037	0.9963	90.00
19.5	3,258,370	135,051	0.0414	0.9586	89.67
20.5	3,103,237	480,963	0.1550	0.8450	85.95
21.5	2,608,768	510	0.0002	0.9998	72.63
22.5	2,520,663	85	0.0000	1.0000	72.62
23.5	2,512,969	9,084	0.0036	0.9964	72.62
24.5	2,502,597	374	0.0001	0.9999	72.35
25.5	2,498,749	1,436	0.0006	0.9994	72.34
26.5	2,466,271	655	0.0003	0.9997	72.30
27.5	2,465,616	4,049	0.0016	0.9984	72.28
28.5	2,458,557	22,073	0.0090	0.9910	72.16
29.5	2,436,484		0.0000	1.0000	71.52
30.5	2,433,642	79,374	0.0326	0.9674	71.52
31.5	1,576,195	29,977	0.0190	0.9810	69.18
32.5	1,497,190		0.0000	1.0000	67.87
33.5	1,484,802		0.0000	1.0000	67.87
34.5	1,482,049		0.0000	1.0000	67.87
35.5	1,194,018		0.0000	1.0000	67.87
36.5					

FORTISBC ENERGY INC.
ACCOUNT 467.10 - TRANS. PLANT - MEAS. & REG. EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

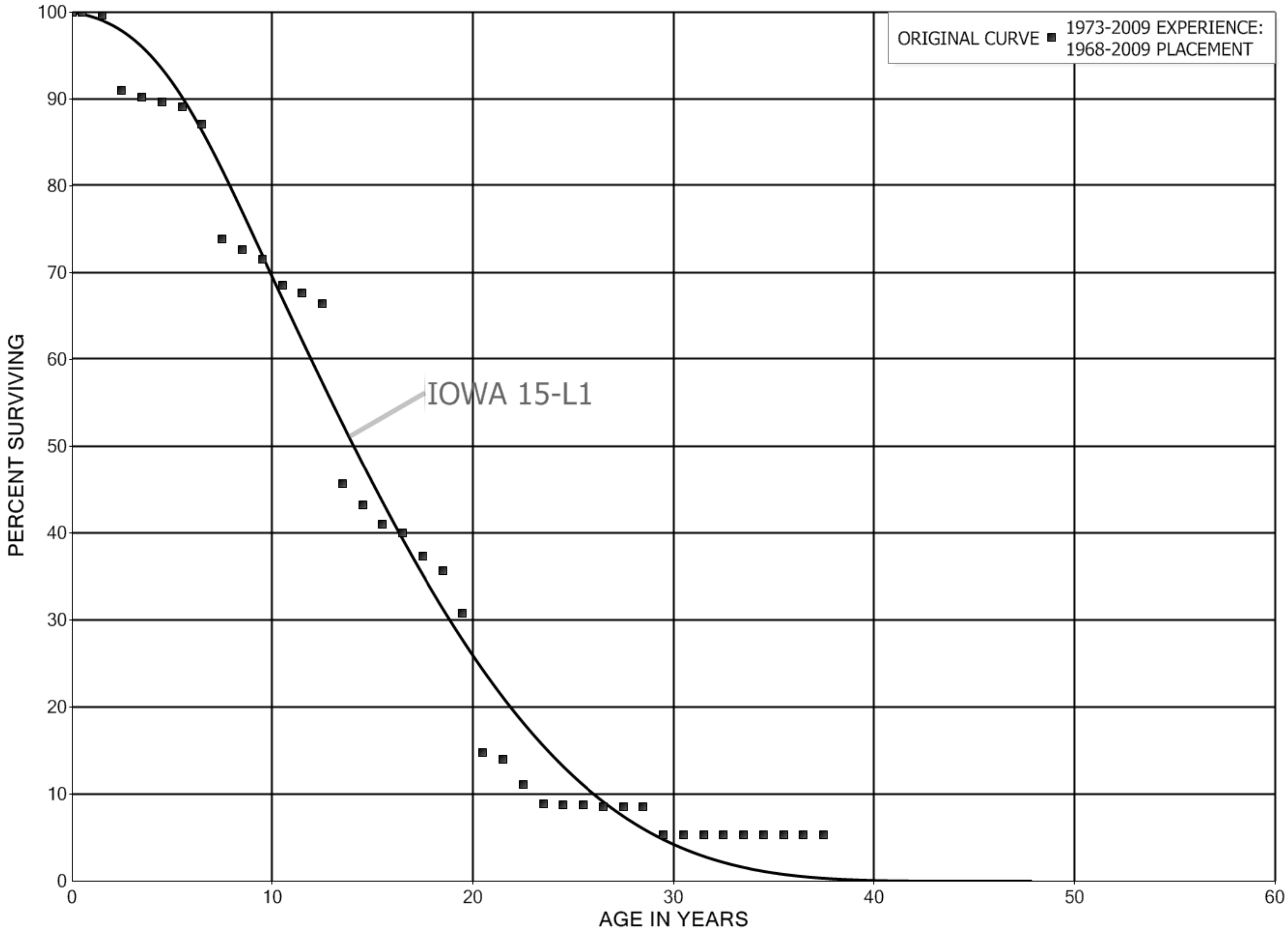
ACCOUNT 467.10 - TRANS. PLANT - MEAS. & REG. EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2009 EXPERIENCE BAND 1968-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,573,309	178,113	0.0053	0.9947	100.00
0.5	33,094,625	11,633	0.0004	0.9996	99.47
1.5	32,984,806	28,212	0.0009	0.9991	99.43
2.5	32,229,638	68,444	0.0021	0.9979	99.35
3.5	31,235,416	105,624	0.0034	0.9966	99.14
4.5	31,034,092	378,143	0.0122	0.9878	98.80
5.5	29,945,544	288,749	0.0096	0.9904	97.60
6.5	25,516,842	247,391	0.0097	0.9903	96.66
7.5	23,008,010	217,557	0.0095	0.9905	95.72
8.5	22,311,071	129,336	0.0058	0.9942	94.82
9.5	18,229,091	226,671	0.0124	0.9876	94.27
10.5	17,607,668	222,731	0.0126	0.9874	93.09
11.5	16,964,109	944,447	0.0557	0.9443	91.92
12.5	12,914,088	190,125	0.0147	0.9853	86.80
13.5	11,806,056	89,387	0.0076	0.9924	85.52
14.5	10,132,130	116,834	0.0115	0.9885	84.87
15.5	9,102,615	1,071,997	0.1178	0.8822	83.90
16.5	6,397,398	129,267	0.0202	0.9798	74.02
17.5	4,633,529	200,554	0.0433	0.9567	72.52
18.5	3,136,120	69,455	0.0221	0.9779	69.38
19.5	3,065,188	153,325	0.0500	0.9500	67.84
20.5	2,854,701	90,065	0.0315	0.9685	64.45
21.5	740,054	4,690	0.0063	0.9937	62.42
22.5	648,172	68,721	0.1060	0.8940	62.02
23.5	541,641	8,095	0.0149	0.9851	55.45
24.5	426,116	8,317	0.0195	0.9805	54.62
25.5	389,746	50,354	0.1292	0.8708	53.55
26.5	339,392	1,249	0.0037	0.9963	46.63
27.5	322,955	7,442	0.0230	0.9770	46.46
28.5	313,679	3,232	0.0103	0.9897	45.39
29.5	310,447	21,090	0.0679	0.9321	44.92
30.5	289,357	44,228	0.1528	0.8472	41.87
31.5	241,641	800	0.0033	0.9967	35.47
32.5	239,803		0.0000	1.0000	35.35
33.5	239,803		0.0000	1.0000	35.35
34.5	238,804	4,450	0.0186	0.9814	35.35
35.5	217,764	37,550	0.1724	0.8276	34.69
36.5	180,214	2,124	0.0118	0.9882	28.71
37.5	52,395		0.0000	1.0000	28.37
38.5					

FORTISBC ENERGY INC.
ACCOUNT 467.20 - TRANS. PLANT - TELEMETRY EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

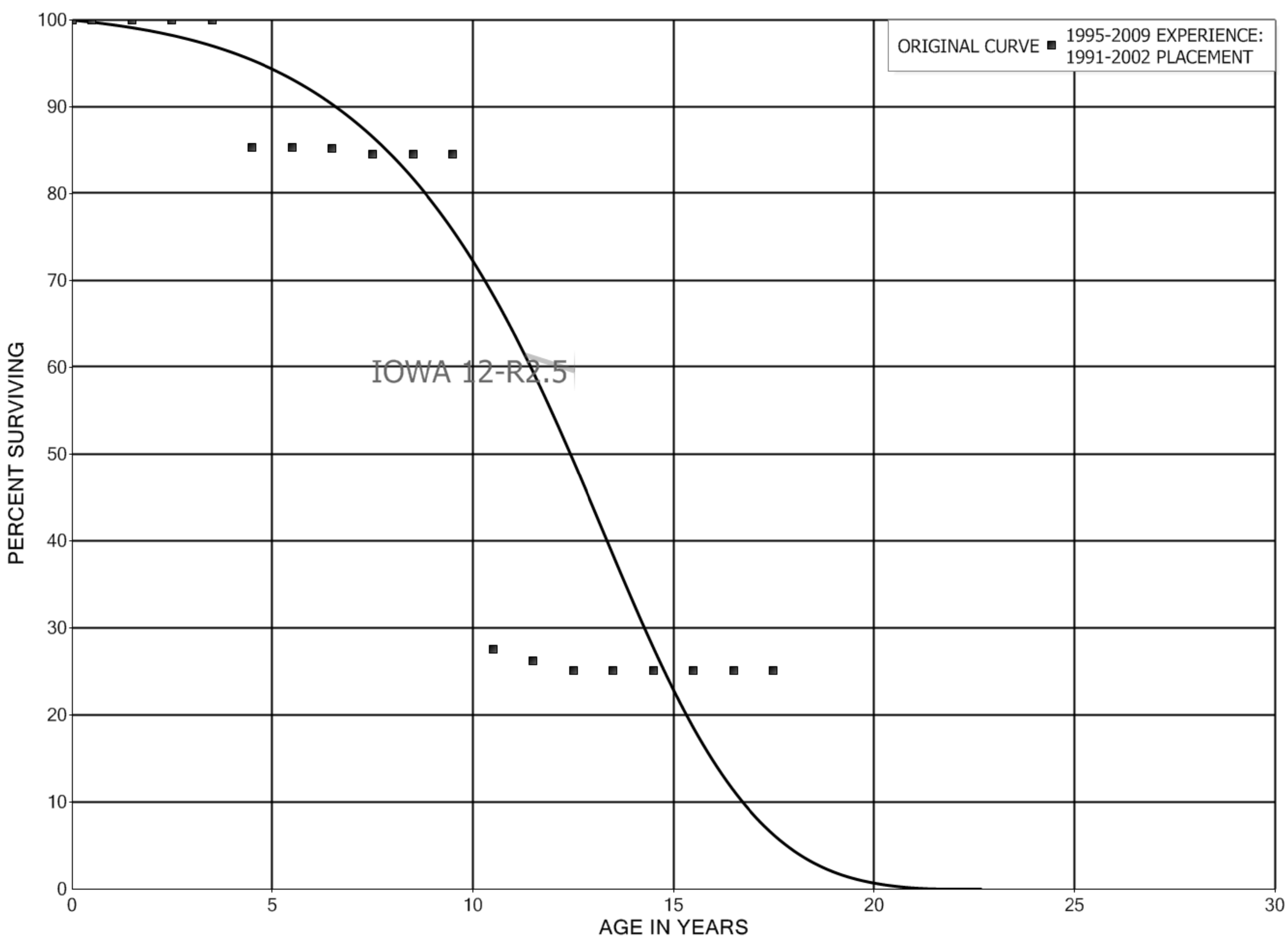
ACCOUNT 467.20 - TRANS. PLANT - TELEMETRY EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2009 EXPERIENCE BAND 1973-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,280,349	12,073	0.0011	0.9989	100.00
0.5	11,369,846	37,206	0.0033	0.9967	99.89
1.5	11,234,978	978,712	0.0871	0.9129	99.57
2.5	10,157,231	83,362	0.0082	0.9918	90.89
3.5	8,935,885	53,988	0.0060	0.9940	90.15
4.5	8,865,546	56,162	0.0063	0.9937	89.60
5.5	8,367,681	185,424	0.0222	0.9778	89.03
6.5	8,077,327	1,223,566	0.1515	0.8485	87.06
7.5	6,692,343	113,571	0.0170	0.9830	73.87
8.5	6,067,274	95,520	0.0157	0.9843	72.62
9.5	5,598,957	235,426	0.0420	0.9580	71.48
10.5	3,497,735	41,519	0.0119	0.9881	68.47
11.5	3,356,498	61,933	0.0185	0.9815	67.66
12.5	3,082,050	962,585	0.3123	0.6877	66.41
13.5	2,035,212	110,366	0.0542	0.9458	45.67
14.5	1,622,676	84,253	0.0519	0.9481	43.19
15.5	1,386,687	32,222	0.0232	0.9768	40.95
16.5	1,231,833	81,868	0.0665	0.9335	40.00
17.5	1,057,845	47,800	0.0452	0.9548	37.34
18.5	880,162	121,714	0.1383	0.8617	35.65
19.5	758,448	394,389	0.5200	0.4800	30.72
20.5	363,098	19,690	0.0542	0.9458	14.75
21.5	330,687	68,456	0.2070	0.7930	13.95
22.5	254,232	51,529	0.2027	0.7973	11.06
23.5	189,002	1,790	0.0095	0.9905	8.82
24.5	152,304	804	0.0053	0.9947	8.73
25.5	142,826	3,628	0.0254	0.9746	8.69
26.5	139,198		0.0000	1.0000	8.47
27.5	130,790		0.0000	1.0000	8.47
28.5	129,136	47,907	0.3710	0.6290	8.47
29.5	53,394		0.0000	1.0000	5.33
30.5	51,954		0.0000	1.0000	5.33
31.5	37,875		0.0000	1.0000	5.33
32.5	33,530		0.0000	1.0000	5.33
33.5	25,270		0.0000	1.0000	5.33
34.5	25,270		0.0000	1.0000	5.33
35.5	20,658		0.0000	1.0000	5.33
36.5	20,658		0.0000	1.0000	5.33
37.5					

FORTISBC ENERGY INC.
ACCOUNT 468.00 - TRANS. PLANT - COMMUNICATIONS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

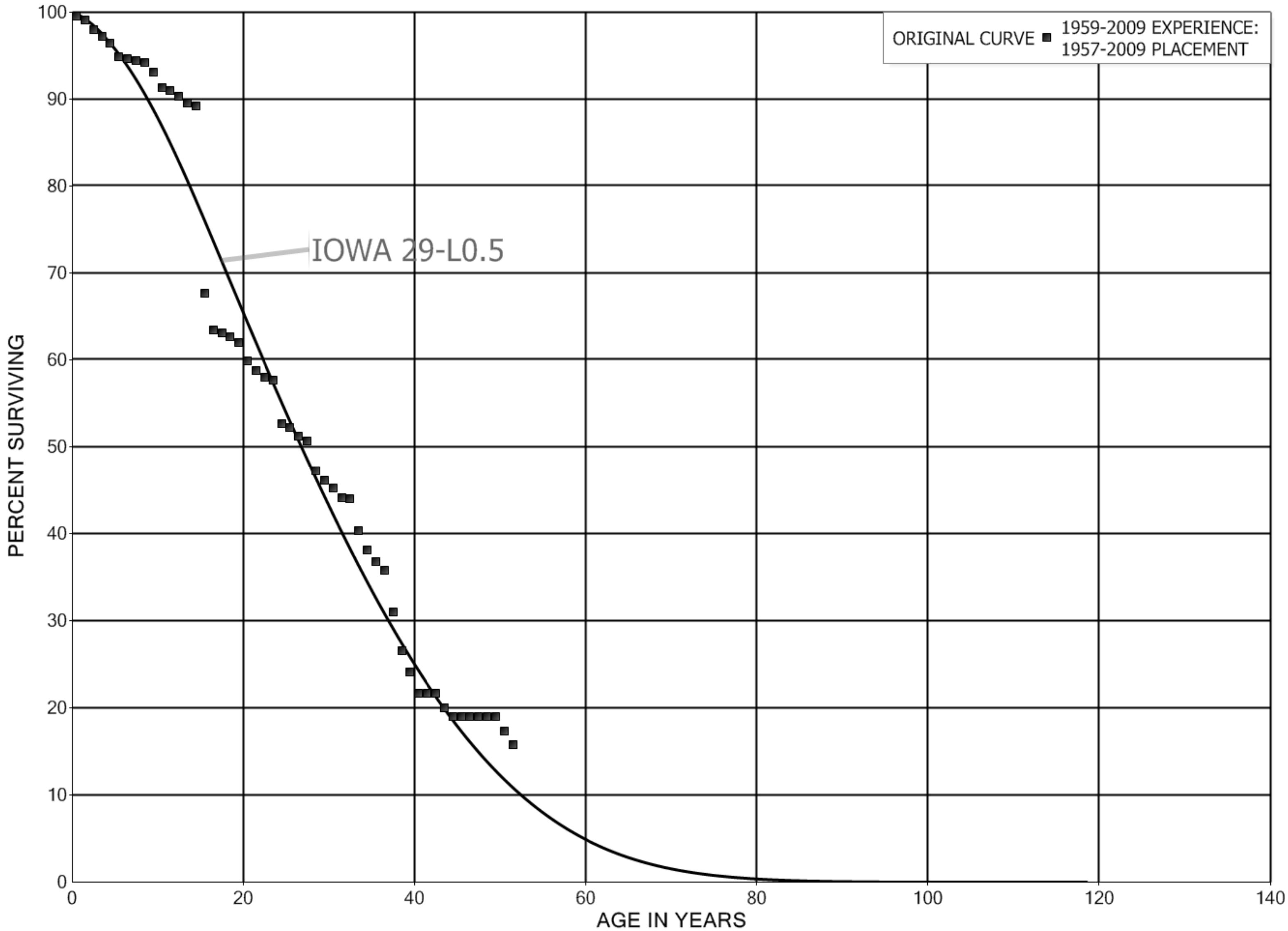
ACCOUNT 468.00 - TRANS. PLANT - COMMUNICATIONS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1991-2002 EXPERIENCE BAND 1995-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	321,185		0.0000	1.0000	100.00
0.5	337,204		0.0000	1.0000	100.00
1.5	560,972		0.0000	1.0000	100.00
2.5	567,246	106	0.0002	0.9998	100.00
3.5	686,534	101,196	0.1474	0.8526	99.98
4.5	585,338		0.0000	1.0000	85.24
5.5	585,338	849	0.0015	0.9985	85.24
6.5	584,489	4,374	0.0075	0.9925	85.12
7.5	535,856		0.0000	1.0000	84.48
8.5	336,491		0.0000	1.0000	84.48
9.5	334,083	225,386	0.6746	0.3254	84.48
10.5	105,683	4,902	0.0464	0.9536	27.49
11.5	89,554	3,942	0.0440	0.9560	26.21
12.5	58,422		0.0000	1.0000	25.06
13.5	54,614		0.0000	1.0000	25.06
14.5	29,602		0.0000	1.0000	25.06
15.5	17,525		0.0000	1.0000	25.06
16.5	5,319		0.0000	1.0000	25.06
17.5					

FORTISBC ENERGY INC.
ACCOUNT 472.00 - DIST. SYSTEM - STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 472.00 - DIST. SYSTEM - STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1959-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,906,972	79,867	0.0047	0.9953	100.00
0.5	16,623,631	75,898	0.0046	0.9954	99.53
1.5	15,812,497	184,496	0.0117	0.9883	99.07
2.5	14,731,191	109,637	0.0074	0.9926	97.92
3.5	12,156,683	96,769	0.0080	0.9920	97.19
4.5	9,805,568	155,256	0.0158	0.9842	96.41
5.5	8,434,007	21,892	0.0026	0.9974	94.89
6.5	8,120,232	20,494	0.0025	0.9975	94.64
7.5	7,877,392	23,416	0.0030	0.9970	94.40
8.5	7,261,868	78,003	0.0107	0.9893	94.12
9.5	6,653,228	130,422	0.0196	0.9804	93.11
10.5	6,095,277	21,341	0.0035	0.9965	91.29
11.5	5,698,701	45,998	0.0081	0.9919	90.97
12.5	4,899,677	37,001	0.0076	0.9924	90.23
13.5	3,849,367	15,044	0.0039	0.9961	89.55
14.5	2,888,665	699,795	0.2423	0.7577	89.20
15.5	1,724,710	105,820	0.0614	0.9386	67.59
16.5	1,461,030	8,733	0.0060	0.9940	63.44
17.5	1,318,296	10,401	0.0079	0.9921	63.07
18.5	990,667	9,043	0.0091	0.9909	62.57
19.5	937,560	32,447	0.0346	0.9654	62.00
20.5	877,430	15,987	0.0182	0.9818	59.85
21.5	844,006	10,791	0.0128	0.9872	58.76
22.5	681,633	4,553	0.0067	0.9933	58.01
23.5	560,412	48,767	0.0870	0.9130	57.62
24.5	495,860	3,875	0.0078	0.9922	52.61
25.5	463,163	8,894	0.0192	0.9808	52.20
26.5	410,195	4,537	0.0111	0.9889	51.19
27.5	380,249	25,704	0.0676	0.9324	50.63
28.5	278,113	6,623	0.0238	0.9762	47.21
29.5	267,214	5,032	0.0188	0.9812	46.08
30.5	258,498	6,871	0.0266	0.9734	45.21
31.5	251,611	331	0.0013	0.9987	44.01
32.5	251,280	21,189	0.0843	0.9157	43.95
33.5	227,903	12,262	0.0538	0.9462	40.25
34.5	214,761	7,637	0.0356	0.9644	38.08
35.5	192,980	5,185	0.0269	0.9731	36.73
36.5	173,815	23,097	0.1329	0.8671	35.74
37.5	146,732	21,057	0.1435	0.8565	30.99
38.5	124,263	11,575	0.0932	0.9068	26.54

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

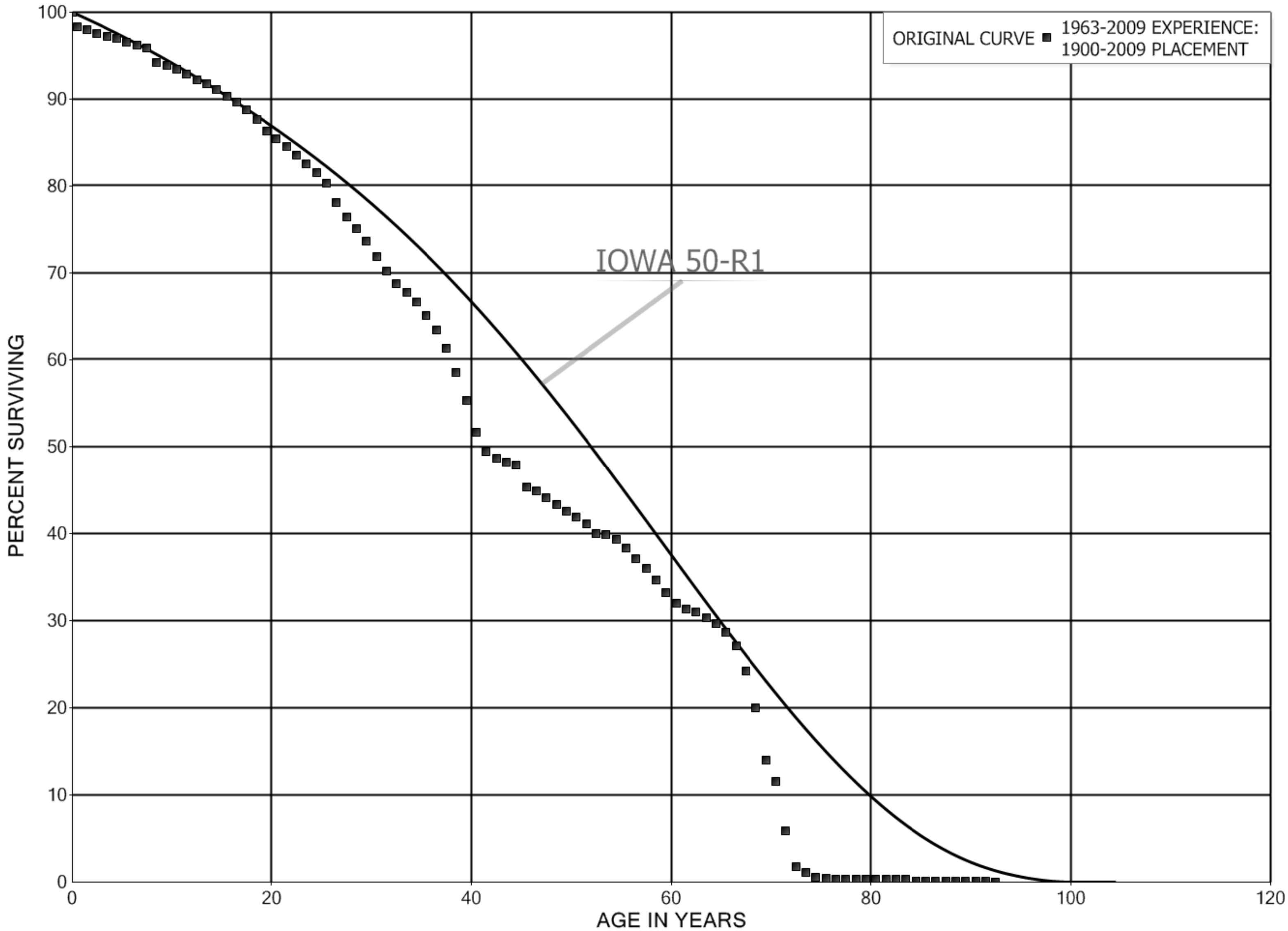
ACCOUNT 472.00 - DIST. SYSTEM - STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1959-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	97,336	9,976	0.1025	0.8975	24.07
40.5	85,526		0.0000	1.0000	21.60
41.5	70,038		0.0000	1.0000	21.60
42.5	70,038	5,444	0.0777	0.9223	21.60
43.5	64,594	3,313	0.0513	0.9487	19.93
44.5	61,281		0.0000	1.0000	18.90
45.5	61,281		0.0000	1.0000	18.90
46.5	61,281		0.0000	1.0000	18.90
47.5	45,873		0.0000	1.0000	18.90
48.5	24,162		0.0000	1.0000	18.90
49.5	24,162	2,024	0.0838	0.9162	18.90
50.5	22,138	2,101	0.0949	0.9051	17.32
51.5					

FORTISBC ENERGY INC.
ACCOUNT 473.00 - DIST. SYSTEM - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 473.00 - DIST. SYSTEM - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	675,536,810	11,950,504	0.0177	0.9823	100.00
0.5	647,335,478	2,170,951	0.0034	0.9966	98.23
1.5	629,619,681	2,284,070	0.0036	0.9964	97.90
2.5	593,030,832	2,068,422	0.0035	0.9965	97.55
3.5	562,279,093	1,799,421	0.0032	0.9968	97.21
4.5	532,765,210	2,050,933	0.0038	0.9962	96.90
5.5	509,222,101	1,872,403	0.0037	0.9963	96.52
6.5	489,684,830	1,927,193	0.0039	0.9961	96.17
7.5	470,805,191	7,776,559	0.0165	0.9835	95.79
8.5	447,792,757	1,616,633	0.0036	0.9964	94.21
9.5	426,132,723	2,366,798	0.0056	0.9944	93.87
10.5	407,003,097	2,373,994	0.0058	0.9942	93.35
11.5	385,634,573	2,699,447	0.0070	0.9930	92.80
12.5	361,941,985	1,638,580	0.0045	0.9955	92.15
13.5	336,502,462	2,507,563	0.0075	0.9925	91.73
14.5	308,448,429	2,445,662	0.0079	0.9921	91.05
15.5	280,539,388	2,324,466	0.0083	0.9917	90.33
16.5	250,189,558	2,490,954	0.0100	0.9900	89.58
17.5	224,254,249	2,766,762	0.0123	0.9877	88.69
18.5	200,045,952	3,014,232	0.0151	0.9849	87.59
19.5	37,566,205	375,679	0.0100	0.9900	86.27
20.5	34,272,048	347,159	0.0101	0.9899	85.41
21.5	32,058,164	399,240	0.0125	0.9875	84.55
22.5	27,708,527	312,082	0.0113	0.9887	83.49
23.5	25,625,000	327,363	0.0128	0.9872	82.55
24.5	21,412,671	329,498	0.0154	0.9846	81.50
25.5	18,777,127	518,864	0.0276	0.9724	80.24
26.5	15,772,789	319,008	0.0202	0.9798	78.03
27.5	13,479,686	235,979	0.0175	0.9825	76.45
28.5	11,184,602	215,898	0.0193	0.9807	75.11
29.5	9,595,543	241,740	0.0252	0.9748	73.66
30.5	8,394,721	188,522	0.0225	0.9775	71.80
31.5	7,323,941	155,848	0.0213	0.9787	70.19
32.5	6,438,106	93,553	0.0145	0.9855	68.70
33.5	5,538,578	91,369	0.0165	0.9835	67.70
34.5	4,902,584	111,224	0.0227	0.9773	66.58
35.5	4,195,586	109,546	0.0261	0.9739	65.07
36.5	3,620,378	120,564	0.0333	0.9667	63.37
37.5	3,158,495	143,838	0.0455	0.9545	61.26
38.5	2,748,873	149,802	0.0545	0.9455	58.47

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 473.00 - DIST. SYSTEM - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,329,730	154,804	0.0664	0.9336	55.29
40.5	2,038,663	89,612	0.0440	0.9560	51.61
41.5	1,845,080	26,432	0.0143	0.9857	49.34
42.5	1,711,995	15,767	0.0092	0.9908	48.64
43.5	1,594,126	12,703	0.0080	0.9920	48.19
44.5	1,469,808	75,825	0.0516	0.9484	47.81
45.5	1,263,116	13,428	0.0106	0.9894	45.34
46.5	1,113,893	18,921	0.0170	0.9830	44.86
47.5	995,911	19,245	0.0193	0.9807	44.10
48.5	976,666	16,551	0.0169	0.9831	43.24
49.5	903,630	14,136	0.0156	0.9844	42.51
50.5	96,666	1,900	0.0197	0.9803	41.85
51.5	94,766	2,469	0.0261	0.9739	41.02
52.5	92,297	389	0.0042	0.9958	39.95
53.5	91,908	1,189	0.0129	0.9871	39.79
54.5	90,719	2,258	0.0249	0.9751	39.27
55.5	88,461	2,800	0.0317	0.9683	38.29
56.5	85,661	2,689	0.0314	0.9686	37.08
57.5	82,972	2,938	0.0354	0.9646	35.92
58.5	80,034	3,372	0.0421	0.9579	34.65
59.5	76,662	2,777	0.0362	0.9638	33.19
60.5	73,885	1,500	0.0203	0.9797	31.98
61.5	72,385	777	0.0107	0.9893	31.33
62.5	71,874	1,686	0.0235	0.9765	31.00
63.5	70,188	1,480	0.0211	0.9789	30.27
64.5	68,708	2,377	0.0346	0.9654	29.63
65.5	66,331	3,544	0.0534	0.9466	28.61
66.5	62,787	6,635	0.1057	0.8943	27.08
67.5	56,152	10,001	0.1781	0.8219	24.22
68.5	46,151	13,679	0.2964	0.7036	19.90
69.5	32,472	5,866	0.1806	0.8194	14.00
70.5	26,606	13,087	0.4919	0.5081	11.47
71.5	13,519	9,566	0.7076	0.2924	5.83
72.5	3,953	1,500	0.3795	0.6205	1.70
73.5	2,453	1,200	0.4892	0.5108	1.06
74.5	1,253	287	0.2291	0.7709	0.54
75.5	966	400	0.4141	0.5859	0.42
76.5	566		0.0000	1.0000	0.24
77.5	566		0.0000	1.0000	0.24
78.5	566		0.0000	1.0000	0.24

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

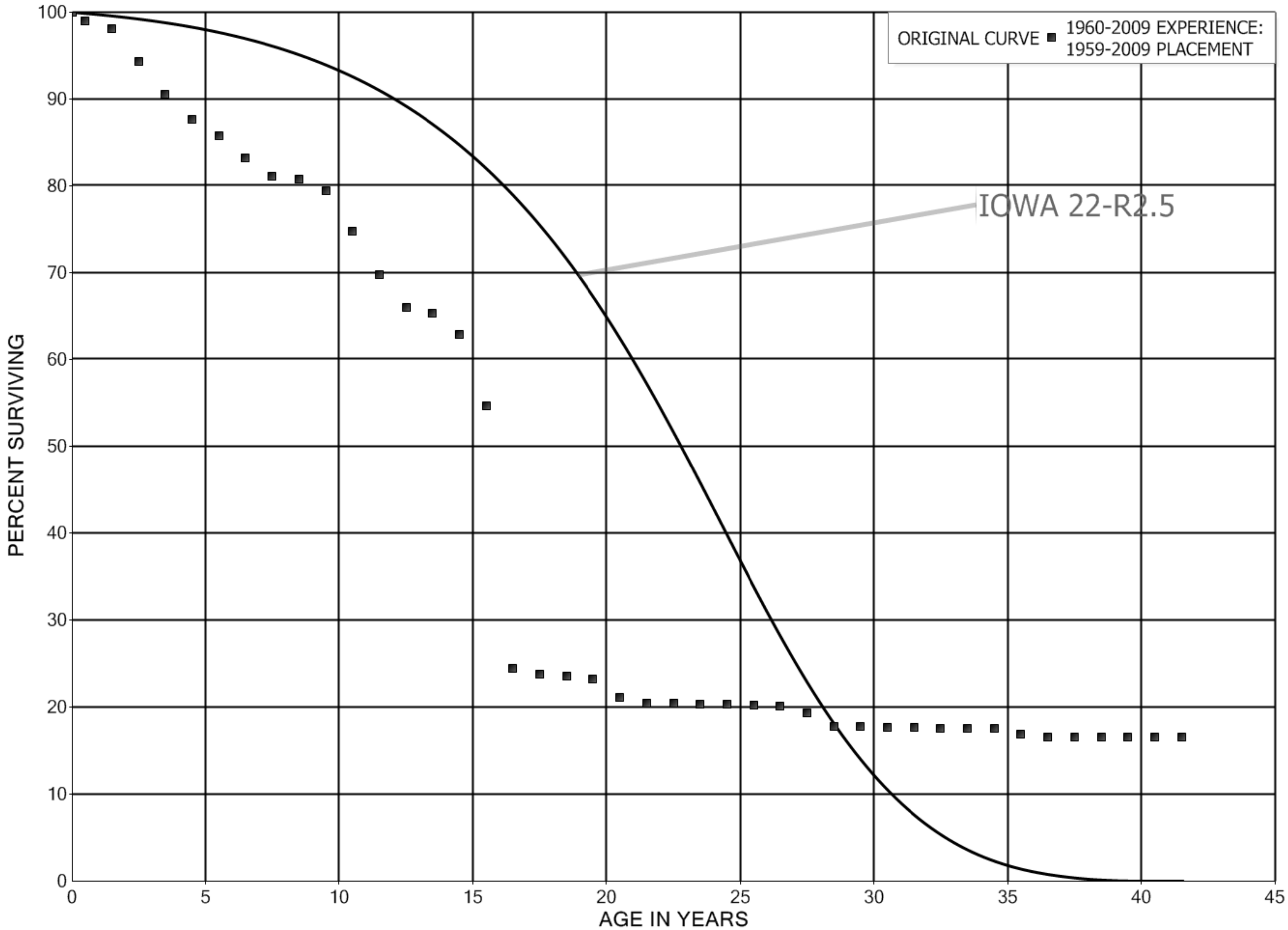
ACCOUNT 473.00 - DIST. SYSTEM - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	566		0.0000	1.0000	0.24
80.5	566		0.0000	1.0000	0.24
81.5	566		0.0000	1.0000	0.24
82.5	566		0.0000	1.0000	0.24
83.5	566	300	0.5300	0.4700	0.24
84.5	266		0.0000	1.0000	0.11
85.5	266		0.0000	1.0000	0.11
86.5	266		0.0000	1.0000	0.11
87.5	266		0.0000	1.0000	0.11
88.5	266		0.0000	1.0000	0.11
89.5	266		0.0000	1.0000	0.11
90.5	266		0.0000	1.0000	0.11
91.5	266	266	1.0000		0.11
92.5					

FORTISBC ENERGY INC.
ACCOUNT 474.00 - DIST. SYSTEM - METERS/REG. INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 474.00 - DIST. SYSTEM - METERS/REG. INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2009 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	182,969,863	1,889,438	0.0103	0.9897	100.00
0.5	173,074,918	1,584,990	0.0092	0.9908	98.97
1.5	168,506,302	6,518,329	0.0387	0.9613	98.06
2.5	151,103,629	5,987,155	0.0396	0.9604	94.27
3.5	134,827,125	4,354,331	0.0323	0.9677	90.53
4.5	121,395,348	2,648,423	0.0218	0.9782	87.61
5.5	110,755,827	3,202,836	0.0289	0.9711	85.70
6.5	102,077,350	2,604,830	0.0255	0.9745	83.22
7.5	93,391,309	455,702	0.0049	0.9951	81.10
8.5	86,961,553	1,410,714	0.0162	0.9838	80.70
9.5	80,245,754	4,731,871	0.0590	0.9410	79.39
10.5	67,932,770	4,564,941	0.0672	0.9328	74.71
11.5	57,634,113	3,099,129	0.0538	0.9462	69.69
12.5	46,239,871	439,648	0.0095	0.9905	65.94
13.5	40,768,770	1,565,015	0.0384	0.9616	65.31
14.5	25,181,154	3,291,610	0.1307	0.8693	62.81
15.5	12,104,946	6,701,473	0.5536	0.4464	54.60
16.5	2,884,669	77,993	0.0270	0.9730	24.37
17.5	2,830,596	29,190	0.0103	0.9897	23.71
18.5	2,796,742	32,063	0.0115	0.9885	23.47
19.5	2,484,575	229,717	0.0925	0.9075	23.20
20.5	2,036,461	61,253	0.0301	0.9699	21.05
21.5	1,601,594	5,656	0.0035	0.9965	20.42
22.5	1,564,818	3,514	0.0022	0.9978	20.35
23.5	1,525,286	5,013	0.0033	0.9967	20.30
24.5	1,473,431	2,589	0.0018	0.9982	20.24
25.5	1,422,594	10,102	0.0071	0.9929	20.20
26.5	1,387,766	52,737	0.0380	0.9620	20.06
27.5	1,091,323	91,069	0.0834	0.9166	19.30
28.5	834,409	651	0.0008	0.9992	17.68
29.5	759,766	600	0.0008	0.9992	17.67
30.5	673,016		0.0000	1.0000	17.66
31.5	510,772	5,825	0.0114	0.9886	17.66
32.5	394,192		0.0000	1.0000	17.46
33.5	344,038		0.0000	1.0000	17.46
34.5	339,586	12,000	0.0353	0.9647	17.46
35.5	244,200	4,281	0.0175	0.9825	16.84
36.5	199,805		0.0000	1.0000	16.54
37.5	166,674		0.0000	1.0000	16.54
38.5	149,399		0.0000	1.0000	16.54

FORTISBC ENERGY INC.

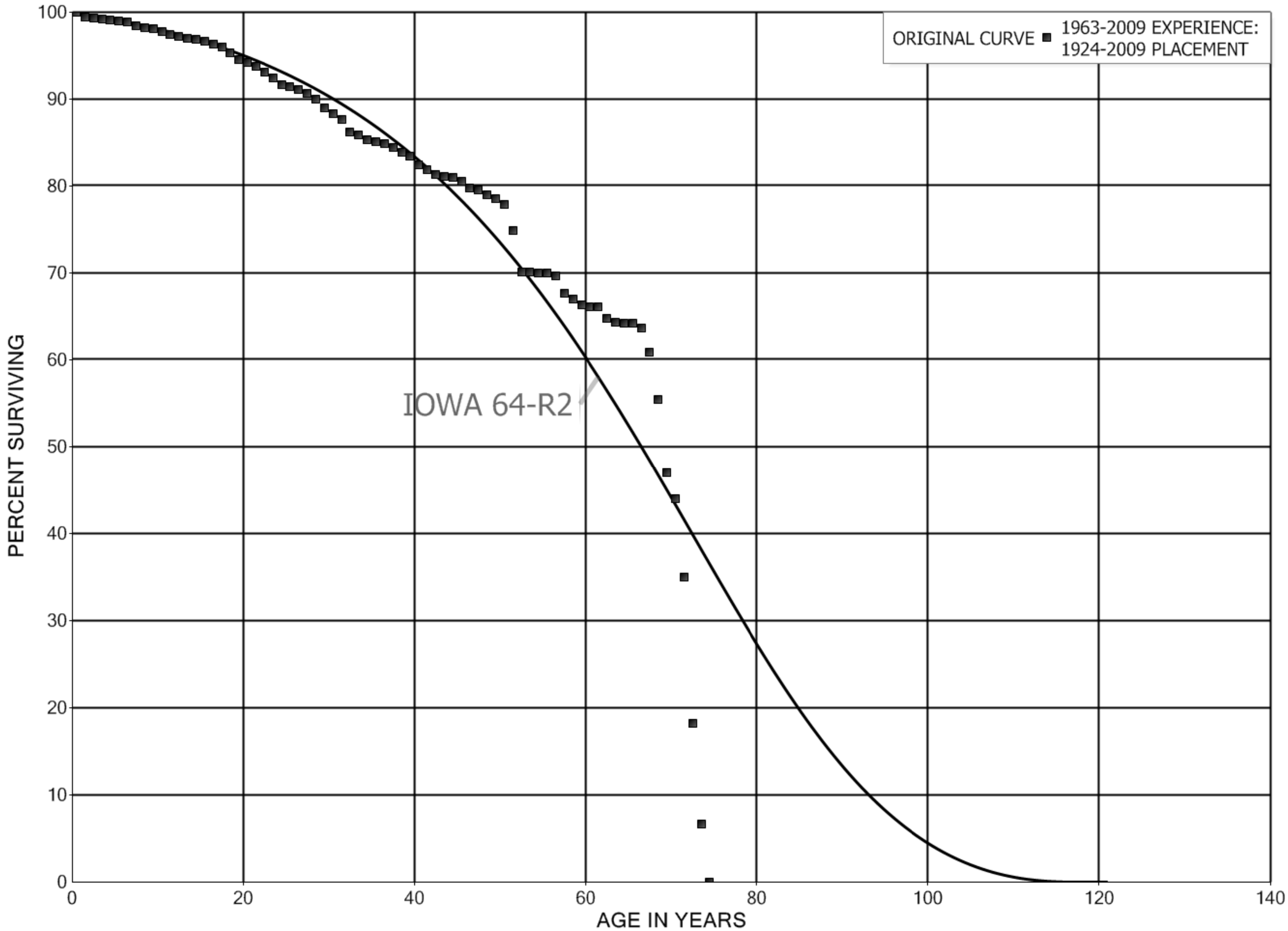
ACCOUNT 474.00 - DIST. SYSTEM - METERS/REG. INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2009 EXPERIENCE BAND 1960-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	101,120		0.0000	1.0000	16.54
40.5	101,120		0.0000	1.0000	16.54
41.5					16.54

FORTISBC ENERGY INC.
ACCOUNT 475.00 - DIST. SYSTEM - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 475.00 - DIST. SYSTEM - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	858,171,531	494,414	0.0006	0.9994	100.00
0.5	837,930,610	4,137,861	0.0049	0.9951	99.94
1.5	819,543,210	1,108,140	0.0014	0.9986	99.45
2.5	790,982,726	902,628	0.0011	0.9989	99.31
3.5	765,147,372	958,413	0.0013	0.9987	99.20
4.5	740,103,247	902,881	0.0012	0.9988	99.08
5.5	717,493,588	1,062,612	0.0015	0.9985	98.96
6.5	693,982,141	2,603,759	0.0038	0.9962	98.81
7.5	669,894,836	1,701,758	0.0025	0.9975	98.44
8.5	646,109,912	843,859	0.0013	0.9987	98.19
9.5	625,317,066	2,325,838	0.0037	0.9963	98.06
10.5	597,301,313	1,587,242	0.0027	0.9973	97.70
11.5	569,656,290	1,484,434	0.0026	0.9974	97.44
12.5	541,861,293	975,524	0.0018	0.9982	97.18
13.5	512,866,219	1,046,627	0.0020	0.9980	97.01
14.5	481,323,926	1,177,810	0.0024	0.9976	96.81
15.5	454,235,923	1,536,344	0.0034	0.9966	96.57
16.5	429,440,298	1,484,336	0.0035	0.9965	96.25
17.5	405,852,375	2,718,708	0.0067	0.9933	95.91
18.5	378,931,113	2,911,124	0.0077	0.9923	95.27
19.5	58,457,497	252,680	0.0043	0.9957	94.54
20.5	55,837,467	216,449	0.0039	0.9961	94.13
21.5	53,765,187	407,460	0.0076	0.9924	93.77
22.5	49,570,663	329,513	0.0066	0.9934	93.05
23.5	46,489,383	388,048	0.0083	0.9917	92.44
24.5	43,596,182	130,614	0.0030	0.9970	91.66
25.5	39,834,921	130,714	0.0033	0.9967	91.39
26.5	32,058,431	158,420	0.0049	0.9951	91.09
27.5	26,984,881	216,536	0.0080	0.9920	90.64
28.5	24,074,821	246,261	0.0102	0.9898	89.91
29.5	20,728,589	153,729	0.0074	0.9926	88.99
30.5	18,192,831	150,202	0.0083	0.9917	88.33
31.5	16,576,451	280,262	0.0169	0.9831	87.60
32.5	15,117,398	54,367	0.0036	0.9964	86.12
33.5	13,728,928	81,825	0.0060	0.9940	85.81
34.5	12,792,407	30,232	0.0024	0.9976	85.30
35.5	11,483,192	34,729	0.0030	0.9970	85.10
36.5	10,499,005	54,091	0.0052	0.9948	84.84
37.5	9,731,764	67,328	0.0069	0.9931	84.40
38.5	9,009,333	44,658	0.0050	0.9950	83.82

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

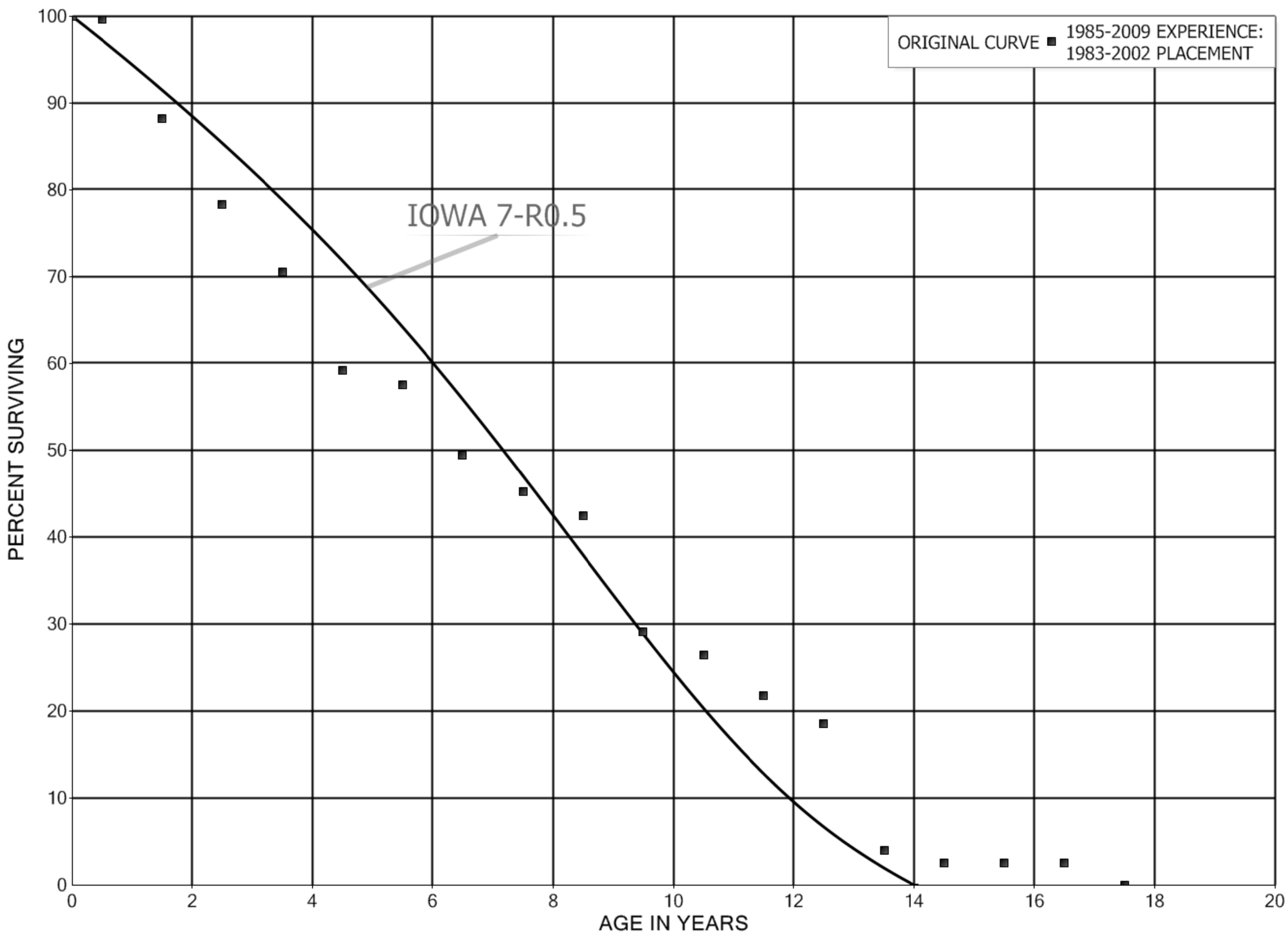
ACCOUNT 475.00 - DIST. SYSTEM - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,529,930	90,765	0.0121	0.9879	83.41
40.5	6,491,156	44,705	0.0069	0.9931	82.40
41.5	5,999,699	39,103	0.0065	0.9935	81.83
42.5	5,605,792	19,085	0.0034	0.9966	81.30
43.5	4,884,175	1,769	0.0004	0.9996	81.02
44.5	4,518,615	24,497	0.0054	0.9946	80.99
45.5	4,033,988	39,157	0.0097	0.9903	80.55
46.5	3,533,055	13,290	0.0038	0.9962	79.77
47.5	3,268,240	22,193	0.0068	0.9932	79.47
48.5	3,161,392	17,527	0.0055	0.9945	78.93
49.5	3,087,700	27,874	0.0090	0.9910	78.49
50.5	139,491	5,340	0.0383	0.9617	77.79
51.5	134,151	8,589	0.0640	0.9360	74.81
52.5	125,562		0.0000	1.0000	70.02
53.5	125,562	54	0.0004	0.9996	70.02
54.5	125,508		0.0000	1.0000	69.99
55.5	125,508	621	0.0049	0.9951	69.99
56.5	124,887	3,684	0.0295	0.9705	69.64
57.5	121,203	1,132	0.0093	0.9907	67.59
58.5	120,071	1,196	0.0100	0.9900	66.96
59.5	118,875	484	0.0041	0.9959	66.29
60.5	118,391		0.0000	1.0000	66.02
61.5	118,391	2,400	0.0203	0.9797	66.02
62.5	115,991	732	0.0063	0.9937	64.68
63.5	115,259	104	0.0009	0.9991	64.27
64.5	115,155		0.0000	1.0000	64.22
65.5	115,155	1,051	0.0091	0.9909	64.22
66.5	114,104	5,097	0.0447	0.9553	63.63
67.5	109,007	9,619	0.0882	0.9118	60.79
68.5	99,388	15,233	0.1533	0.8467	55.42
69.5	84,155	5,371	0.0638	0.9362	46.93
70.5	78,784	16,139	0.2049	0.7951	43.93
71.5	62,645	30,099	0.4805	0.5195	34.93
72.5	32,546	20,729	0.6369	0.3631	18.15
73.5	11,817	11,817	1.0000		6.59
74.5					

FORTISBC ENERGY INC.
ACCOUNT 476.00 - DIST. SYSTEM - NGV FUEL EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

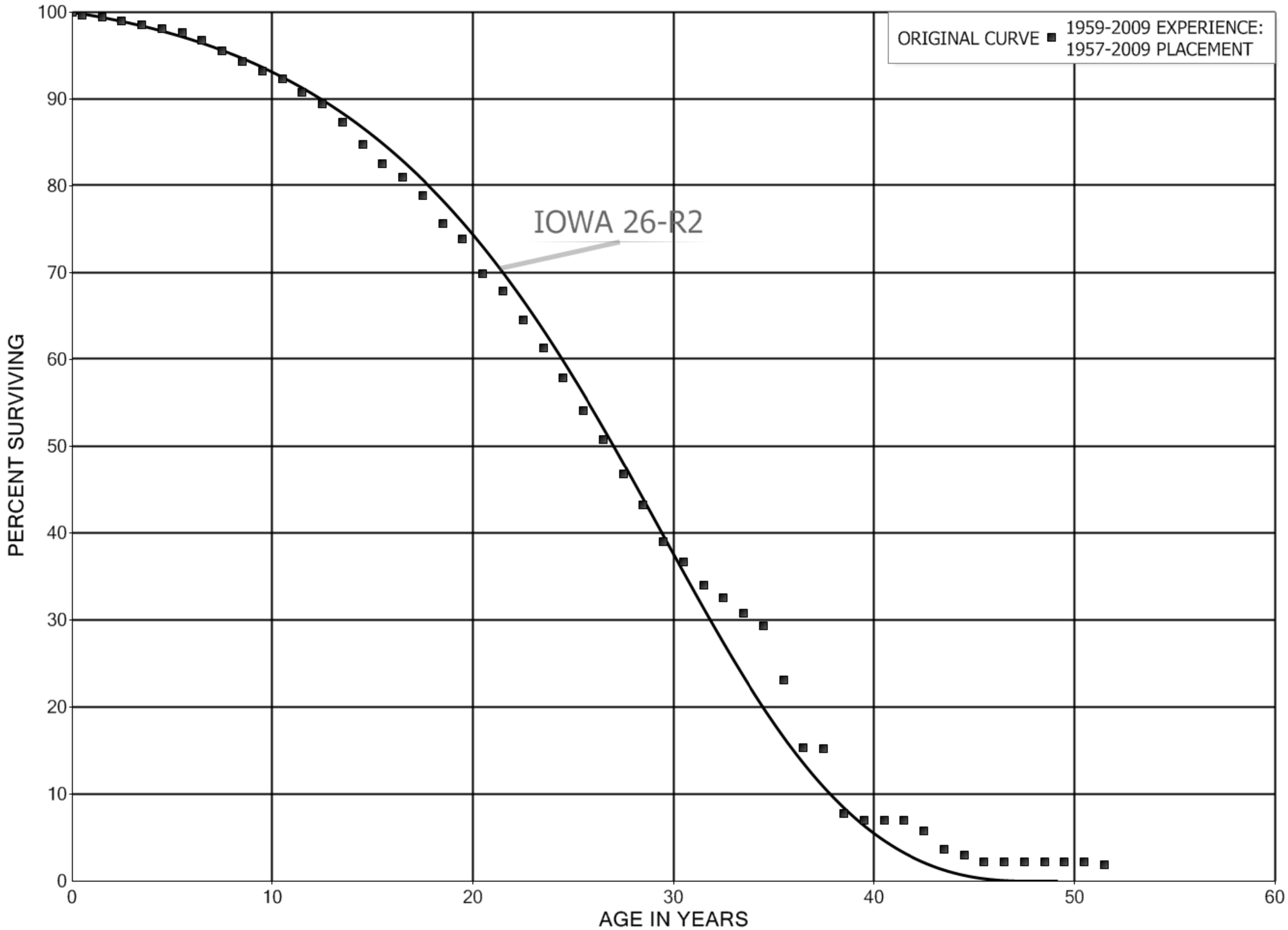
ACCOUNT 476.00 - DIST. SYSTEM - NGV FUEL EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2002 EXPERIENCE BAND 1985-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,605,576	41,918	0.0044	0.9956	100.00
0.5	9,566,083	1,096,943	0.1147	0.8853	99.56
1.5	8,689,260	969,105	0.1115	0.8885	88.15
2.5	7,720,155	765,596	0.0992	0.9008	78.32
3.5	6,954,559	1,125,829	0.1619	0.8381	70.55
4.5	5,828,730	156,311	0.0268	0.9732	59.13
5.5	5,672,418	808,111	0.1425	0.8575	57.54
6.5	4,864,307	407,191	0.0837	0.9163	49.35
7.5	4,413,618	278,800	0.0632	0.9368	45.21
8.5	4,094,164	1,279,856	0.3126	0.6874	42.36
9.5	2,547,644	236,715	0.0929	0.9071	29.12
10.5	2,260,721	399,241	0.1766	0.8234	26.41
11.5	1,811,326	273,868	0.1512	0.8488	21.75
12.5	1,481,210	1,159,465	0.7828	0.2172	18.46
13.5	258,313	99,250	0.3842	0.6158	4.01
14.5	159,063		0.0000	1.0000	2.47
15.5	159,063		0.0000	1.0000	2.47
16.5	159,063	159,063	1.0000		2.47
17.5					

FORTISBC ENERGY INC.
ACCOUNT 477.10 - DIST. SYSTEM - MEAS. & REG. ADDITIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 477.10 - DIST. SYSTEM - MEAS. & REG. ADDITIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1959-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	88,644,113	343,490	0.0039	0.9961	100.00
0.5	86,566,270	206,229	0.0024	0.9976	99.61
1.5	85,681,244	390,381	0.0046	0.9954	99.38
2.5	79,570,503	320,871	0.0040	0.9960	98.92
3.5	71,352,396	330,233	0.0046	0.9954	98.52
4.5	66,157,896	335,591	0.0051	0.9949	98.07
5.5	62,050,654	507,887	0.0082	0.9918	97.57
6.5	53,593,813	719,098	0.0134	0.9866	96.77
7.5	49,647,707	634,632	0.0128	0.9872	95.47
8.5	44,379,708	485,243	0.0109	0.9891	94.25
9.5	40,343,594	412,189	0.0102	0.9898	93.22
10.5	37,962,559	636,030	0.0168	0.9832	92.27
11.5	35,173,671	535,559	0.0152	0.9848	90.72
12.5	31,566,622	727,211	0.0230	0.9770	89.34
13.5	27,710,191	800,172	0.0289	0.9711	87.28
14.5	22,404,058	604,351	0.0270	0.9730	84.76
15.5	19,321,091	350,957	0.0182	0.9818	82.48
16.5	17,261,585	460,257	0.0267	0.9733	80.98
17.5	15,556,346	628,571	0.0404	0.9596	78.82
18.5	13,925,493	325,024	0.0233	0.9767	75.64
19.5	13,461,075	727,986	0.0541	0.9459	73.87
20.5	12,262,448	365,819	0.0298	0.9702	69.87
21.5	4,486,076	221,005	0.0493	0.9507	67.79
22.5	3,785,362	187,848	0.0496	0.9504	64.45
23.5	2,972,558	163,728	0.0551	0.9449	61.25
24.5	2,705,466	176,576	0.0653	0.9347	57.88
25.5	2,363,199	149,361	0.0632	0.9368	54.10
26.5	1,977,555	152,670	0.0772	0.9228	50.68
27.5	1,637,512	124,663	0.0761	0.9239	46.77
28.5	1,497,187	147,551	0.0986	0.9014	43.21
29.5	1,270,700	74,532	0.0587	0.9413	38.95
30.5	1,124,165	81,643	0.0726	0.9274	36.67
31.5	1,038,182	45,452	0.0438	0.9562	34.00
32.5	983,806	53,292	0.0542	0.9458	32.51
33.5	897,397	43,097	0.0480	0.9520	30.75
34.5	850,981	181,324	0.2131	0.7869	29.28
35.5	658,480	222,123	0.3373	0.6627	23.04
36.5	349,765	2,938	0.0084	0.9916	15.27
37.5	346,827	170,946	0.4929	0.5071	15.14
38.5	170,127	16,969	0.0997	0.9003	7.68

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

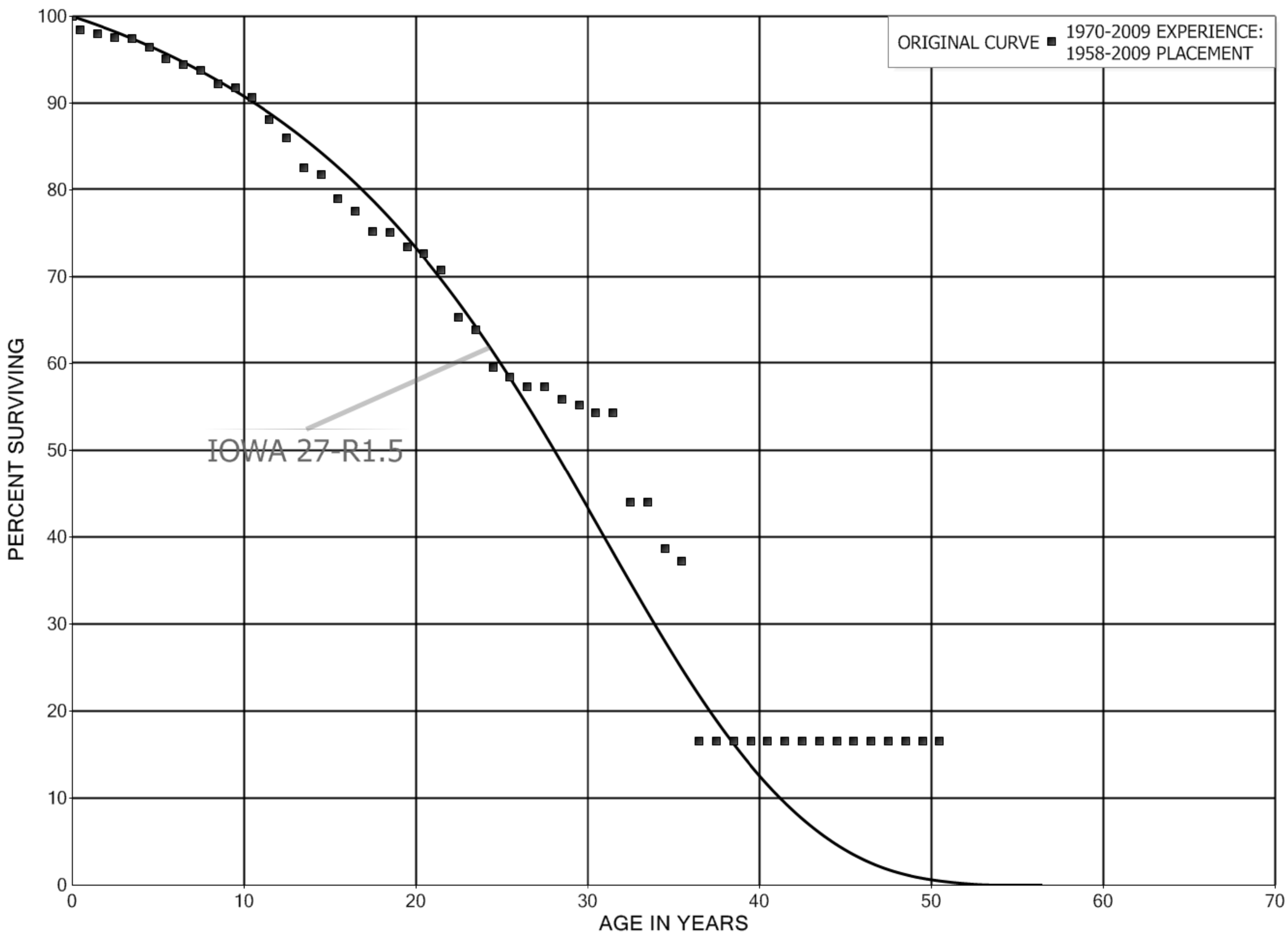
ACCOUNT 477.10 - DIST. SYSTEM - MEAS. & REG. ADDITIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1959-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	143,796		0.0000	1.0000	6.91
40.5	133,503		0.0000	1.0000	6.91
41.5	133,503	22,833	0.1710	0.8290	6.91
42.5	110,670	40,318	0.3643	0.6357	5.73
43.5	69,813	13,615	0.1950	0.8050	3.64
44.5	55,413	13,855	0.2500	0.7500	2.93
45.5	41,343		0.0000	1.0000	2.20
46.5	41,343		0.0000	1.0000	2.20
47.5	41,343		0.0000	1.0000	2.20
48.5	41,343		0.0000	1.0000	2.20
49.5	41,343		0.0000	1.0000	2.20
50.5	41,343	6,204	0.1501	0.8499	2.20
51.5					

FORTISBC ENERGY INC.
ACCOUNT 477.20 - DIST. SYSTEM - TELEMETRY
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 477.20 - DIST. SYSTEM - TELEMETRY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2009 EXPERIENCE BAND 1970-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,578,936	105,932	0.0161	0.9839	100.00
0.5	6,410,806	25,599	0.0040	0.9960	98.39
1.5	6,359,736	28,437	0.0045	0.9955	98.00
2.5	6,283,484	13,274	0.0021	0.9979	97.56
3.5	6,107,999	58,975	0.0097	0.9903	97.35
4.5	6,010,289	83,246	0.0139	0.9861	96.41
5.5	5,806,843	40,873	0.0070	0.9930	95.08
6.5	5,311,451	39,288	0.0074	0.9926	94.41
7.5	5,012,877	79,348	0.0158	0.9842	93.71
8.5	4,569,263	25,079	0.0055	0.9945	92.23
9.5	4,236,544	50,564	0.0119	0.9881	91.72
10.5	3,906,818	110,892	0.0284	0.9716	90.63
11.5	3,492,228	82,549	0.0236	0.9764	88.05
12.5	2,849,204	115,858	0.0407	0.9593	85.97
13.5	1,204,558	11,280	0.0094	0.9906	82.48
14.5	909,916	30,213	0.0332	0.9668	81.70
15.5	653,595	12,451	0.0190	0.9810	78.99
16.5	530,063	15,647	0.0295	0.9705	77.49
17.5	419,436	1,040	0.0025	0.9975	75.20
18.5	383,564	8,031	0.0209	0.9791	75.01
19.5	360,055	4,183	0.0116	0.9884	73.44
20.5	346,933	8,738	0.0252	0.9748	72.59
21.5	283,310	21,774	0.0769	0.9231	70.76
22.5	260,929	6,133	0.0235	0.9765	65.32
23.5	183,088	12,290	0.0671	0.9329	63.79
24.5	132,967	2,588	0.0195	0.9805	59.50
25.5	128,013	2,374	0.0185	0.9815	58.35
26.5	76,576		0.0000	1.0000	57.26
27.5	58,908	1,472	0.0250	0.9750	57.26
28.5	57,436	643	0.0112	0.9888	55.83
29.5	56,792	955	0.0168	0.9832	55.21
30.5	41,459		0.0000	1.0000	54.28
31.5	41,459	7,932	0.1913	0.8087	54.28
32.5	33,526		0.0000	1.0000	43.89
33.5	33,331	4,013	0.1204	0.8796	43.89
34.5	29,317	1,075	0.0367	0.9633	38.61
35.5	28,242	15,708	0.5562	0.4438	37.19
36.5	9,820		0.0000	1.0000	16.51
37.5	9,820		0.0000	1.0000	16.51
38.5	9,679		0.0000	1.0000	16.51

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

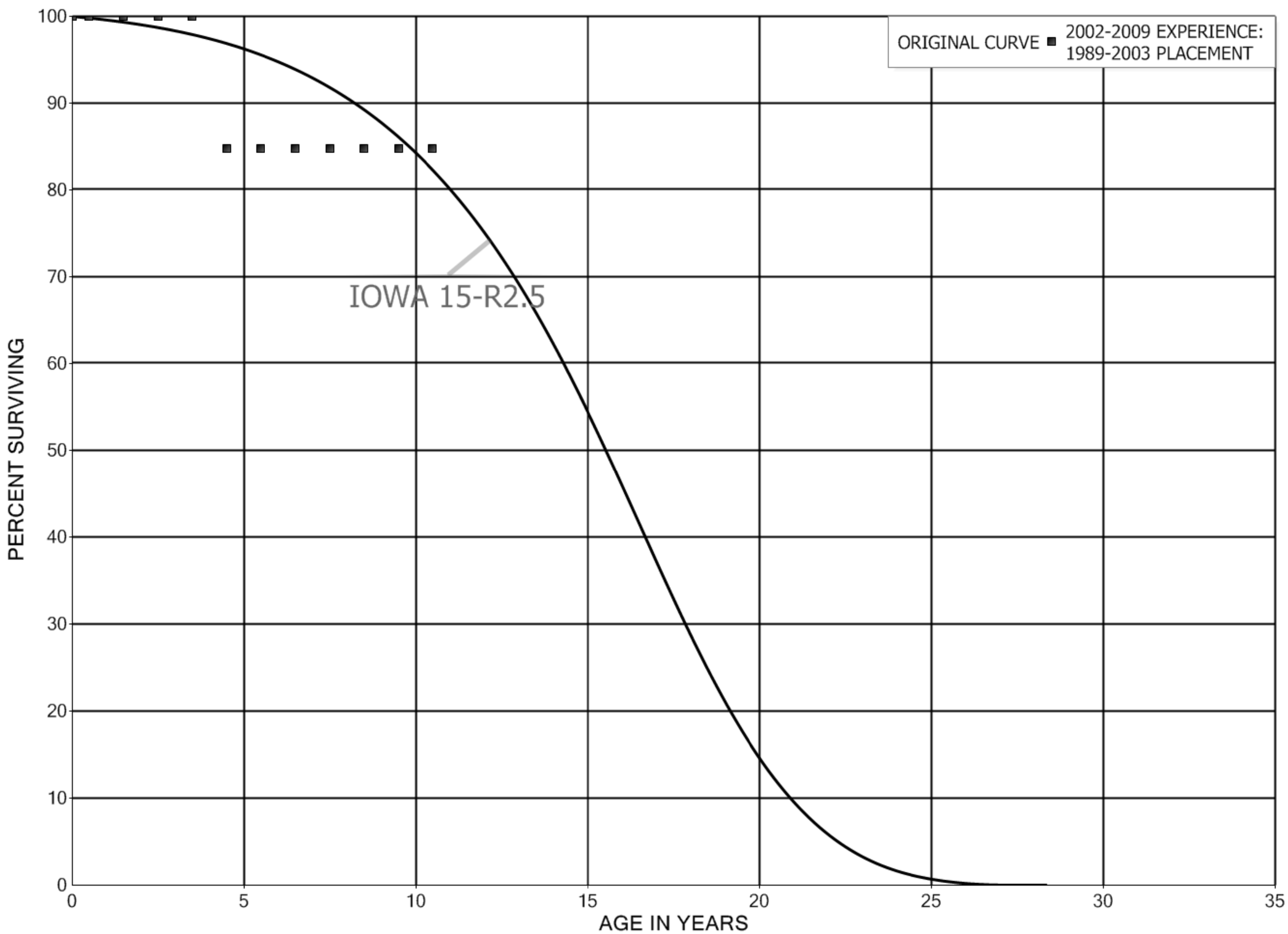
ACCOUNT 477.20 - DIST. SYSTEM - TELEMETRY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1958-2009 EXPERIENCE BAND 1970-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	9,679		0.0000	1.0000	16.51
40.5	203		0.0000	1.0000	16.51
41.5	203		0.0000	1.0000	16.51
42.5	203		0.0000	1.0000	16.51
43.5	203		0.0000	1.0000	16.51
44.5	203		0.0000	1.0000	16.51
45.5	203		0.0000	1.0000	16.51
46.5	203		0.0000	1.0000	16.51
47.5	203		0.0000	1.0000	16.51
48.5	203		0.0000	1.0000	16.51
49.5	203		0.0000	1.0000	16.51
50.5					

FORTISBC ENERGY INC.
ACCOUNT 477.30 - DIST. SYSTEM - MEAS. & REG. EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

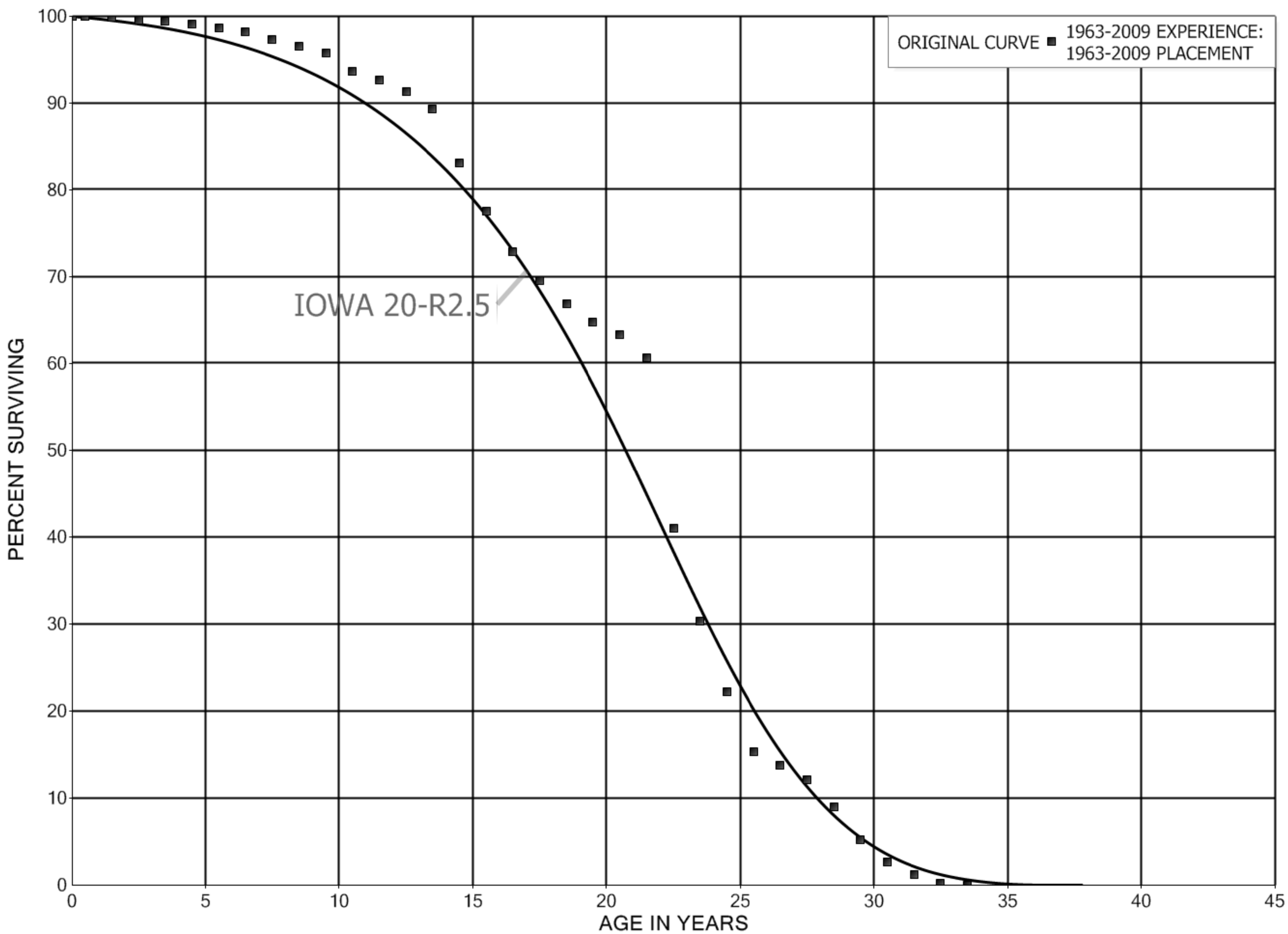
ACCOUNT 477.30 - DIST. SYSTEM - MEAS. & REG. EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2003 EXPERIENCE BAND 2002-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	49,223		0.0000	1.0000	100.00
0.5	93,287		0.0000	1.0000	100.00
1.5	94,948		0.0000	1.0000	100.00
2.5	100,134		0.0000	1.0000	100.00
3.5	118,160	18,026	0.1526	0.8474	100.00
4.5	100,134		0.0000	1.0000	84.74
5.5	100,134		0.0000	1.0000	84.74
6.5	63,358		0.0000	1.0000	84.74
7.5	63,358		0.0000	1.0000	84.74
8.5	19,294		0.0000	1.0000	84.74
9.5	17,633		0.0000	1.0000	84.74
10.5	12,701		0.0000	1.0000	84.74
11.5	12,701		0.0000	1.0000	84.74
12.5	63,017		0.0000	1.0000	84.74
13.5	63,017		0.0000	1.0000	84.74
14.5	50,570		0.0000	1.0000	84.74
15.5	50,570		0.0000	1.0000	84.74
16.5	50,570		0.0000	1.0000	84.74
17.5	50,570		0.0000	1.0000	84.74
18.5	50,316		0.0000	1.0000	84.74
19.5	50,316		0.0000	1.0000	84.74
20.5					

FORTISBC ENERGY INC.
ACCOUNT 478.10 - DIST. SYSTEM - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 478.10 - DIST. SYSTEM - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	236,024,526	144,891	0.0006	0.9994	100.00
0.5	226,998,252	240,371	0.0011	0.9989	99.94
1.5	218,945,986	610,489	0.0028	0.9972	99.83
2.5	208,799,512	429,108	0.0021	0.9979	99.55
3.5	200,378,073	669,840	0.0033	0.9967	99.35
4.5	191,319,703	752,882	0.0039	0.9961	99.02
5.5	177,422,059	764,181	0.0043	0.9957	98.63
6.5	160,518,877	1,485,816	0.0093	0.9907	98.20
7.5	147,668,356	1,240,442	0.0084	0.9916	97.29
8.5	140,748,938	1,038,726	0.0074	0.9926	96.48
9.5	131,745,324	2,957,480	0.0224	0.9776	95.76
10.5	119,100,774	1,223,717	0.0103	0.9897	93.62
11.5	110,404,961	1,673,481	0.0152	0.9848	92.65
12.5	101,151,076	2,118,155	0.0209	0.9791	91.25
13.5	89,778,117	6,309,763	0.0703	0.9297	89.34
14.5	75,385,905	5,005,865	0.0664	0.9336	83.06
15.5	65,318,831	3,957,709	0.0606	0.9394	77.54
16.5	57,504,804	2,620,272	0.0456	0.9544	72.85
17.5	51,049,020	1,963,185	0.0385	0.9615	69.53
18.5	45,953,843	1,463,997	0.0319	0.9681	66.85
19.5	32,210,467	730,086	0.0227	0.9773	64.72
20.5	25,783,942	1,087,052	0.0422	0.9578	63.26
21.5	6,838,032	2,215,075	0.3239	0.6761	60.59
22.5	4,622,957	1,201,785	0.2600	0.7400	40.96
23.5	3,421,172	924,184	0.2701	0.7299	30.31
24.5	2,496,988	772,620	0.3094	0.6906	22.12
25.5	1,724,368	179,868	0.1043	0.8957	15.28
26.5	1,544,500	187,992	0.1217	0.8783	13.69
27.5	1,356,508	348,232	0.2567	0.7433	12.02
28.5	1,003,285	421,739	0.4204	0.5796	8.93
29.5	576,193	287,219	0.4985	0.5015	5.18
30.5	285,898	152,679	0.5340	0.4660	2.60
31.5	133,219	114,772	0.8615	0.1385	1.21
32.5	18,447	18,397	0.9973	0.0027	0.17
33.5	50		0.0000	1.0000	0.00
34.5	50		0.0000	1.0000	0.00
35.5	50		0.0000	1.0000	0.00
36.5	50		0.0000	1.0000	0.00
37.5	50		0.0000	1.0000	0.00
38.5	50		0.0000	1.0000	0.00

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

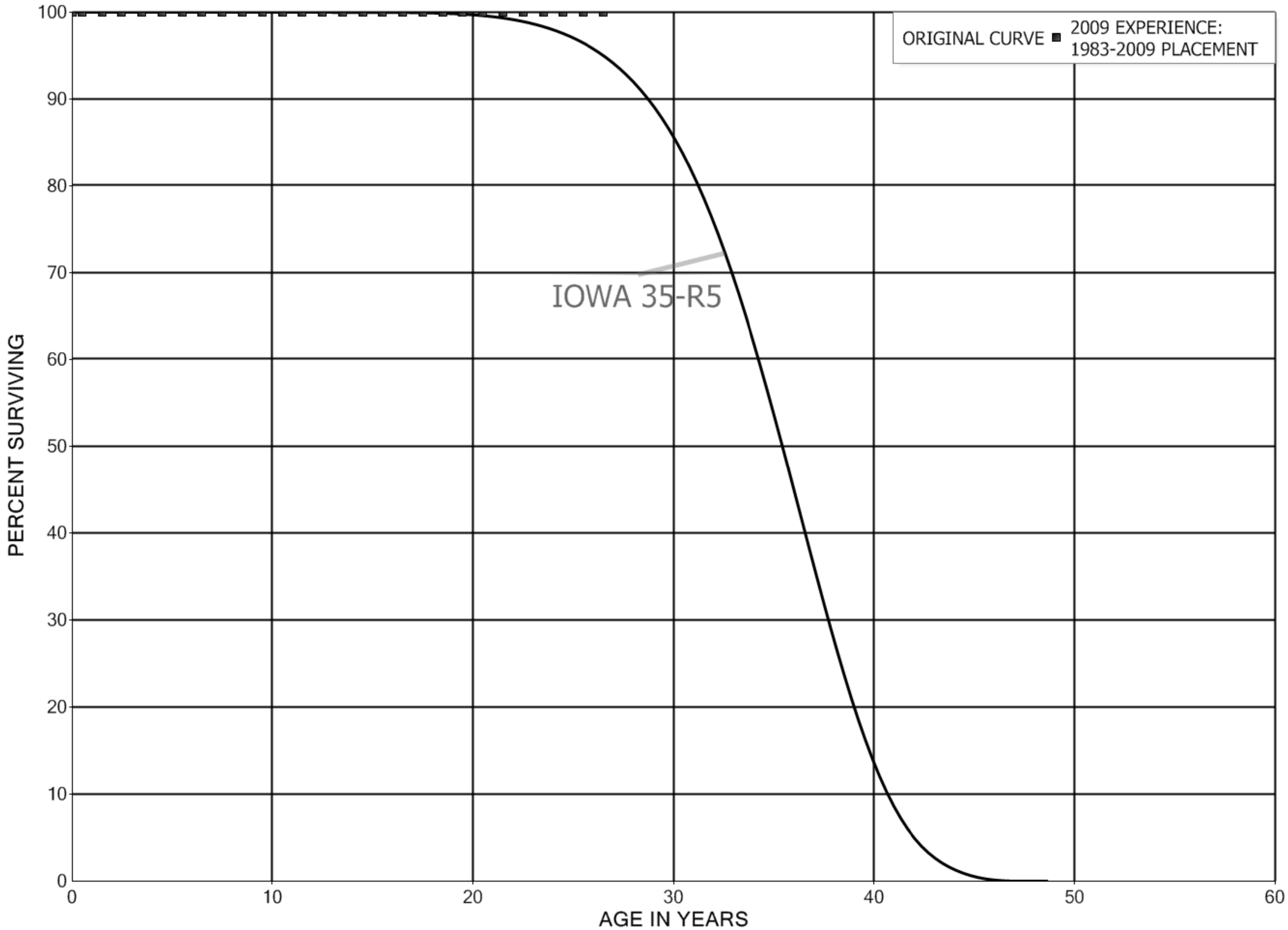
ACCOUNT 478.10 - DIST. SYSTEM - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	50		0.0000	1.0000	0.00
40.5	50		0.0000	1.0000	0.00
41.5	50		0.0000	1.0000	0.00
42.5	50		0.0000	1.0000	0.00
43.5	50		0.0000	1.0000	0.00
44.5	50		0.0000	1.0000	0.00
45.5					

FORTISBC ENERGY INC.
ACCOUNT 478.20 - DIST. SYSTEM INSTRUMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

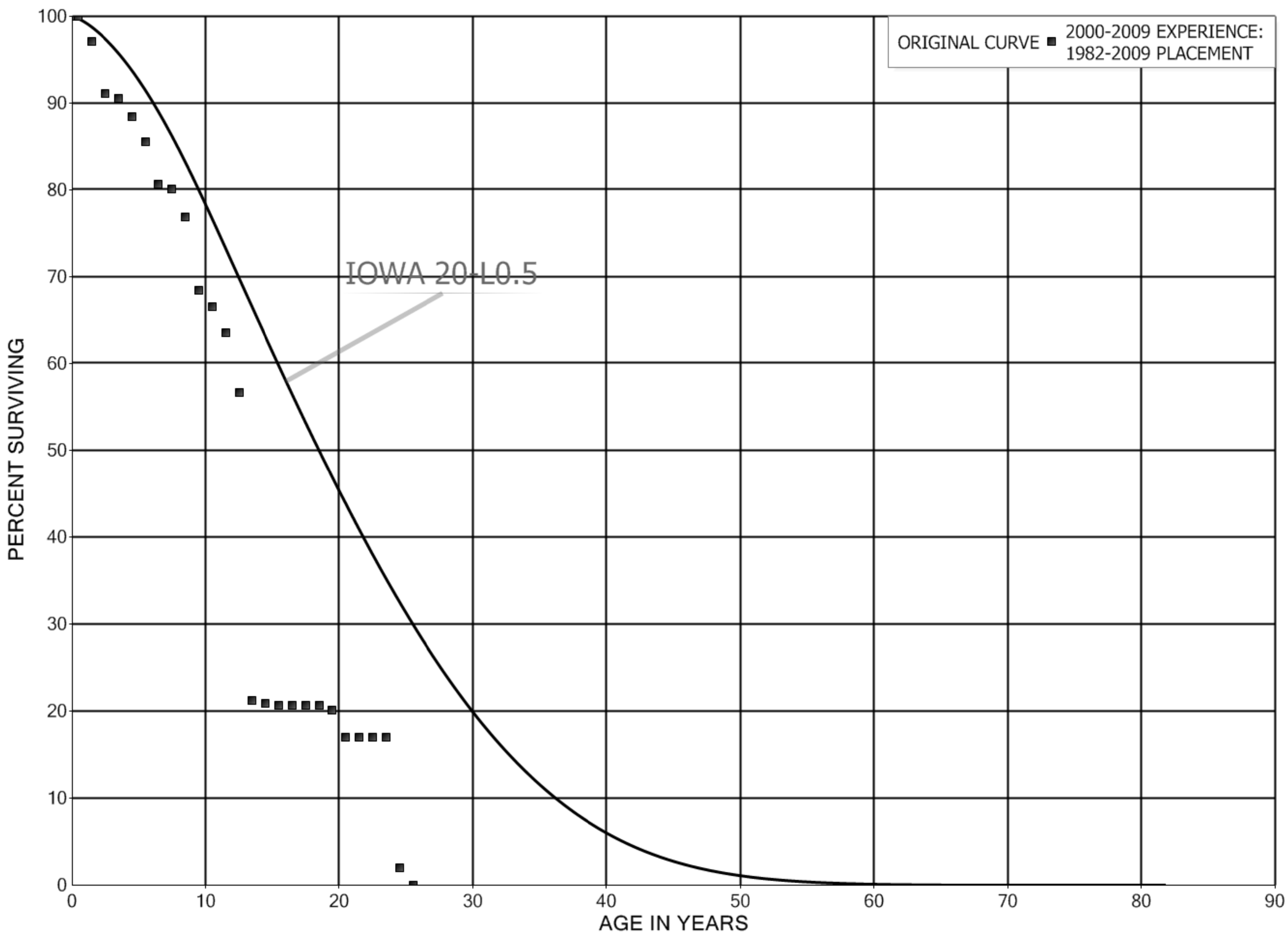
ACCOUNT 478.20 - DIST. SYSTEM INSTRUMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2009 EXPERIENCE BAND 2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	53,797		0.0000	1.0000	100.00
0.5	308,437		0.0000	1.0000	100.00
1.5	447,713		0.0000	1.0000	100.00
2.5	508,057		0.0000	1.0000	100.00
3.5	288,291		0.0000	1.0000	100.00
4.5	1,363,377		0.0000	1.0000	100.00
5.5	1,390,662		0.0000	1.0000	100.00
6.5	356,604		0.0000	1.0000	100.00
7.5	375,867		0.0000	1.0000	100.00
8.5	253,792		0.0000	1.0000	100.00
9.5	354,932		0.0000	1.0000	100.00
10.5	53,828		0.0000	1.0000	100.00
11.5	407,432		0.0000	1.0000	100.00
12.5	655,671		0.0000	1.0000	100.00
13.5	785,627		0.0000	1.0000	100.00
14.5	901,190		0.0000	1.0000	100.00
15.5	835,661		0.0000	1.0000	100.00
16.5	754,660		0.0000	1.0000	100.00
17.5	344,503		0.0000	1.0000	100.00
18.5	165,438		0.0000	1.0000	100.00
19.5	93,986		0.0000	1.0000	100.00
20.5	115,161		0.0000	1.0000	100.00
21.5	96,808		0.0000	1.0000	100.00
22.5	23,356		0.0000	1.0000	100.00
23.5	5,631		0.0000	1.0000	100.00
24.5	2,933		0.0000	1.0000	100.00
25.5	361,762		0.0000	1.0000	100.00
26.5					

FORTISBC ENERGY INC.
ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

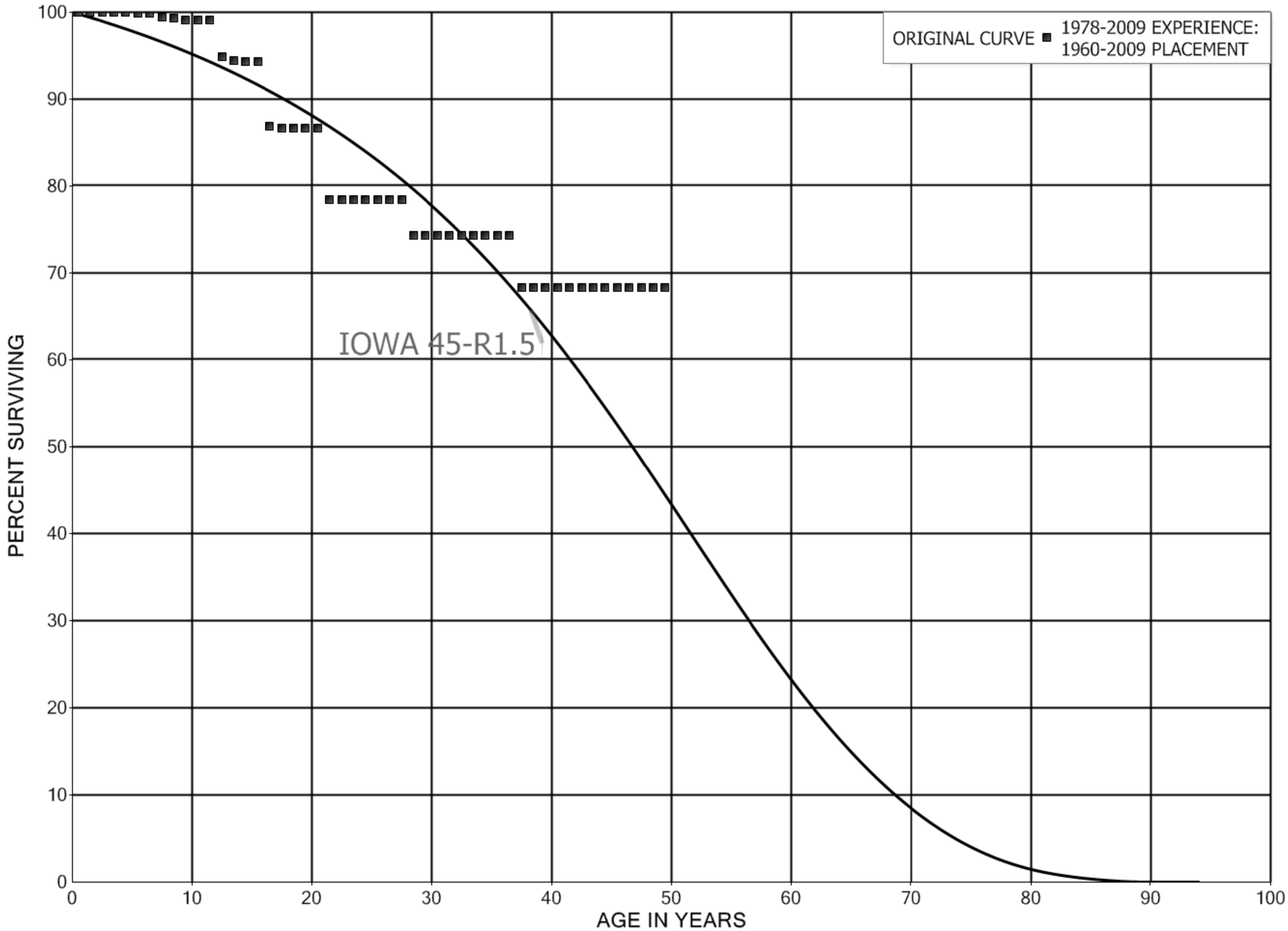
ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2009 EXPERIENCE BAND 2000-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,284,557	1,593	0.0005	0.9995	100.00
0.5	2,600,509	74,690	0.0287	0.9713	99.95
1.5	2,882,065	177,884	0.0617	0.9383	97.08
2.5	2,791,734	19,013	0.0068	0.9932	91.09
3.5	3,656,413	82,123	0.0225	0.9775	90.47
4.5	3,533,794	119,066	0.0337	0.9663	88.44
5.5	4,058,596	228,606	0.0563	0.9437	85.46
6.5	3,717,837	28,183	0.0076	0.9924	80.64
7.5	3,948,391	155,188	0.0393	0.9607	80.03
8.5	3,298,861	364,249	0.1104	0.8896	76.89
9.5	2,735,304	75,021	0.0274	0.9726	68.40
10.5	2,520,749	113,202	0.0449	0.9551	66.52
11.5	8,432,663	911,273	0.1081	0.8919	63.53
12.5	7,406,862	4,635,492	0.6258	0.3742	56.67
13.5	1,878,270	36,088	0.0192	0.9808	21.20
14.5	1,835,455	14,372	0.0078	0.9922	20.80
15.5	1,204,943		0.0000	1.0000	20.63
16.5	1,201,535		0.0000	1.0000	20.63
17.5	1,174,075		0.0000	1.0000	20.63
18.5	1,003,487	28,873	0.0288	0.9712	20.63
19.5	974,614	150,670	0.1546	0.8454	20.04
20.5	823,944	1,909	0.0023	0.9977	16.94
21.5	28,099		0.0000	1.0000	16.90
22.5	28,099		0.0000	1.0000	16.90
23.5	28,099	24,783	0.8820	0.1180	16.90
24.5	3,316	3,316	1.0000		1.99
25.5					

FORTISBC ENERGY INC.
ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1978-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	84,012,941	12,000	0.0001	0.9999	100.00
0.5	83,291,645	40,054	0.0005	0.9995	99.99
1.5	82,282,308	396	0.0000	1.0000	99.94
2.5	78,989,761		0.0000	1.0000	99.94
3.5	77,917,739	6,229	0.0001	0.9999	99.94
4.5	26,290,489	32,473	0.0012	0.9988	99.93
5.5	25,225,749	4,411	0.0002	0.9998	99.81
6.5	23,730,459	85,556	0.0036	0.9964	99.79
7.5	23,213,313	34,252	0.0015	0.9985	99.43
8.5	21,934,196	38,626	0.0018	0.9982	99.28
9.5	21,284,239	1,840	0.0001	0.9999	99.11
10.5	21,192,881	6,520	0.0003	0.9997	99.10
11.5	19,810,017	856,492	0.0432	0.9568	99.07
12.5	18,506,795	67,312	0.0036	0.9964	94.78
13.5	14,073,863	20,937	0.0015	0.9985	94.44
14.5	9,789,070		0.0000	1.0000	94.30
15.5	6,025,105	477,881	0.0793	0.9207	94.30
16.5	5,405,431	10,000	0.0018	0.9982	86.82
17.5	2,168,160		0.0000	1.0000	86.66
18.5	2,140,536		0.0000	1.0000	86.66
19.5	2,025,697		0.0000	1.0000	86.66
20.5	1,573,022	150,222	0.0955	0.9045	86.66
21.5	895,606		0.0000	1.0000	78.38
22.5	892,256		0.0000	1.0000	78.38
23.5	892,010		0.0000	1.0000	78.38
24.5	890,923		0.0000	1.0000	78.38
25.5	845,385		0.0000	1.0000	78.38
26.5	834,344		0.0000	1.0000	78.38
27.5	826,589	42,784	0.0518	0.9482	78.38
28.5	774,836		0.0000	1.0000	74.33
29.5	769,915		0.0000	1.0000	74.33
30.5	464,087		0.0000	1.0000	74.33
31.5	443,730		0.0000	1.0000	74.33
32.5	434,803		0.0000	1.0000	74.33
33.5	186,033		0.0000	1.0000	74.33
34.5	185,852		0.0000	1.0000	74.33
35.5	185,163		0.0000	1.0000	74.33
36.5	185,163	15,000	0.0810	0.9190	74.33
37.5	170,163		0.0000	1.0000	68.31
38.5	170,163		0.0000	1.0000	68.31

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

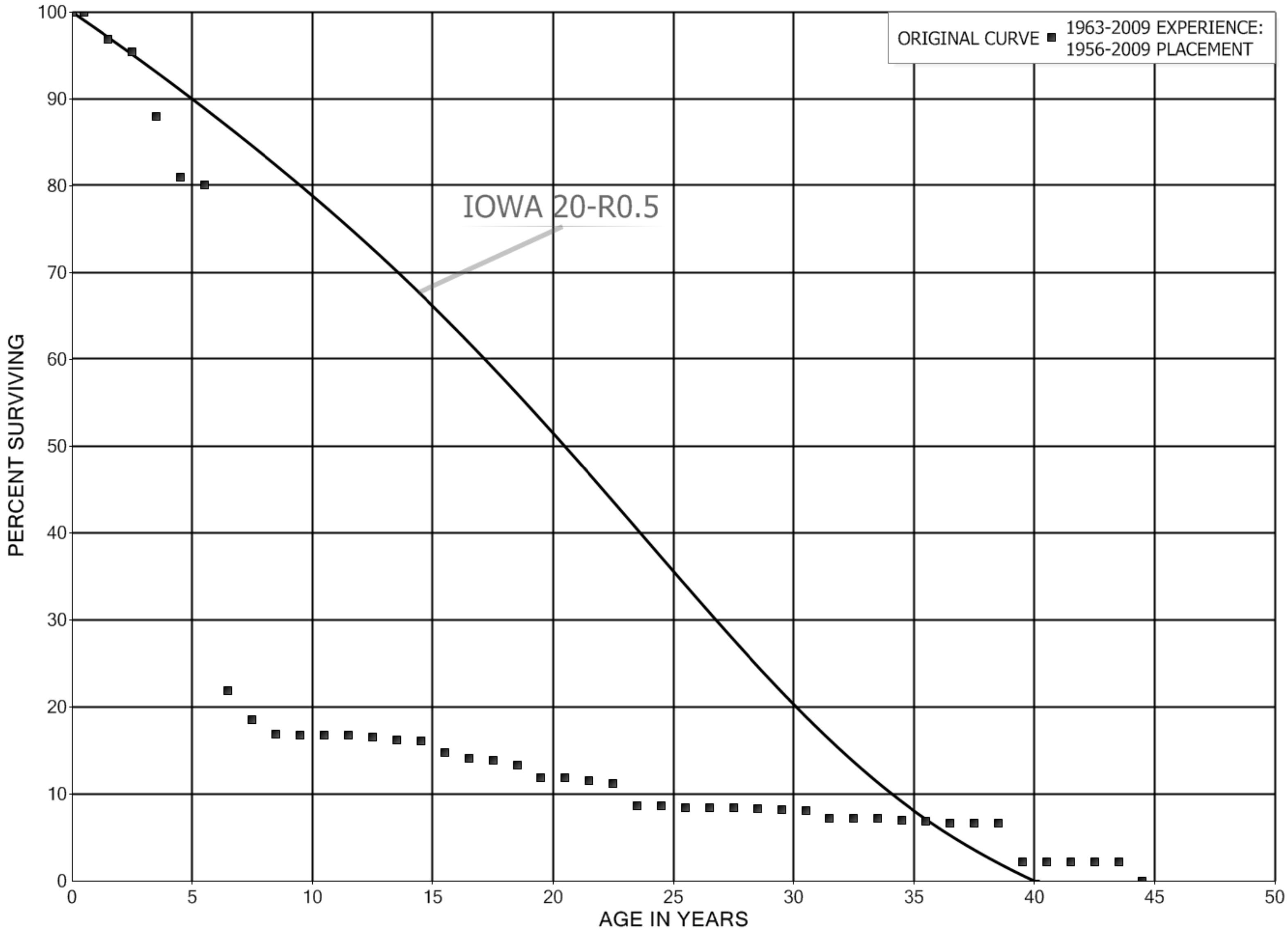
ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2009 EXPERIENCE BAND 1978-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	156,331		0.0000	1.0000	68.31
40.5	156,331		0.0000	1.0000	68.31
41.5	156,331		0.0000	1.0000	68.31
42.5	85,734		0.0000	1.0000	68.31
43.5	85,734		0.0000	1.0000	68.31
44.5	85,734		0.0000	1.0000	68.31
45.5	85,734		0.0000	1.0000	68.31
46.5	85,734		0.0000	1.0000	68.31
47.5	85,734		0.0000	1.0000	68.31
48.5	85,734		0.0000	1.0000	68.31
49.5					

FORTISBC ENERGY INC.
ACCOUNT 482.30 - GENERAL PLANT - STRUCTURES (LEASED)
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 482.30 - GENERAL PLANT - STRUCTURES (LEASED)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,242,407	10,661	0.0006	0.9994	100.00
0.5	19,212,556	592,409	0.0308	0.9692	99.94
1.5	18,666,076	289,655	0.0155	0.9845	96.86
2.5	18,395,958	1,419,270	0.0772	0.9228	95.36
3.5	16,976,689	1,362,241	0.0802	0.9198	88.00
4.5	15,755,687	173,482	0.0110	0.9890	80.94
5.5	15,581,016	11,327,048	0.7270	0.2730	80.05
6.5	5,123,491	797,925	0.1557	0.8443	21.86
7.5	4,325,565	375,690	0.0869	0.9131	18.45
8.5	3,949,875	21,557	0.0055	0.9945	16.85
9.5	3,928,318	5,655	0.0014	0.9986	16.76
10.5	3,922,663	10,984	0.0028	0.9972	16.73
11.5	3,911,679	54,002	0.0138	0.9862	16.69
12.5	3,857,677	66,560	0.0173	0.9827	16.46
13.5	3,791,117	23,554	0.0062	0.9938	16.17
14.5	3,767,563	314,059	0.0834	0.9166	16.07
15.5	3,453,504	168,721	0.0489	0.9511	14.73
16.5	3,284,782	46,271	0.0141	0.9859	14.01
17.5	3,238,511	112,042	0.0346	0.9654	13.81
18.5	3,126,470	355,339	0.1137	0.8863	13.34
19.5	2,771,131		0.0000	1.0000	11.82
20.5	2,771,131	82,176	0.0297	0.9703	11.82
21.5	2,688,955	74,239	0.0276	0.9724	11.47
22.5	2,614,716	600,904	0.2298	0.7702	11.15
23.5	2,013,812	2,439	0.0012	0.9988	8.59
24.5	2,011,373	40,043	0.0199	0.9801	8.58
25.5	1,971,330	10,000	0.0051	0.9949	8.41
26.5	1,961,330	3,175	0.0016	0.9984	8.37
27.5	1,958,155	11,243	0.0057	0.9943	8.35
28.5	1,946,912	27,762	0.0143	0.9857	8.31
29.5	1,919,151	37,125	0.0193	0.9807	8.19
30.5	1,882,026	188,202	0.1000	0.9000	8.03
31.5	1,693,823		0.0000	1.0000	7.23
32.5	1,693,823		0.0000	1.0000	7.23
33.5	1,693,823	65,724	0.0388	0.9612	7.23
34.5	1,628,099	20,001	0.0123	0.9877	6.95
35.5	1,608,098	46,646	0.0290	0.9710	6.86
36.5	1,561,452	4,224	0.0027	0.9973	6.66
37.5	1,557,228		0.0000	1.0000	6.64
38.5	1,557,228	1,046,586	0.6721	0.3279	6.64

FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

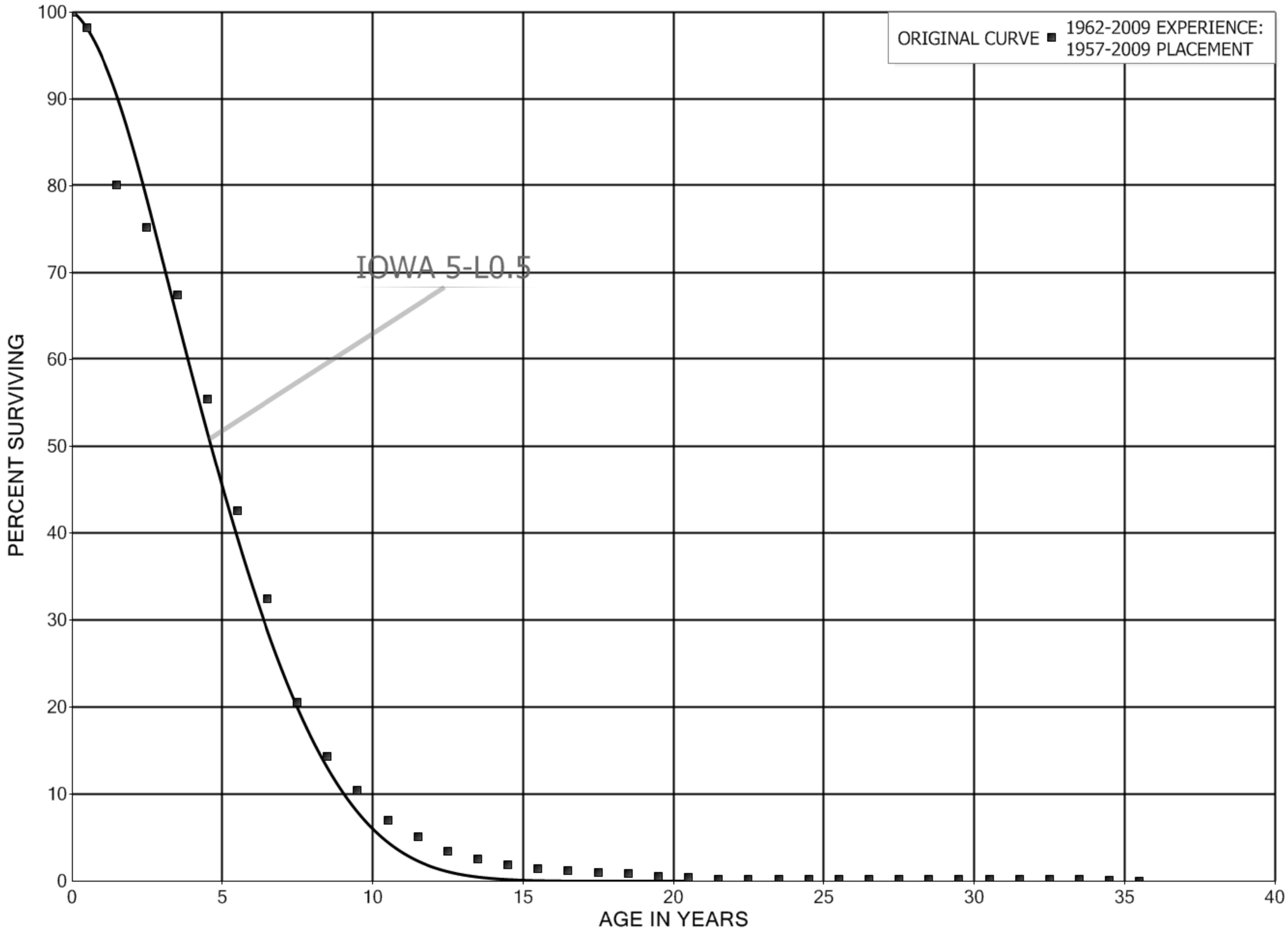
ACCOUNT 482.30 - GENERAL PLANT - STRUCTURES (LEASED)

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2009 EXPERIENCE BAND 1963-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	510,642		0.0000	1.0000	2.18
40.5	510,642		0.0000	1.0000	2.18
41.5	510,642		0.0000	1.0000	2.18
42.5	510,642		0.0000	1.0000	2.18
43.5	510,642	510,642	1.0000		2.18
44.5					

FORTISBC ENERGY INC.
ACCOUNT 484.00 - GENERAL PLANT - VEHICLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

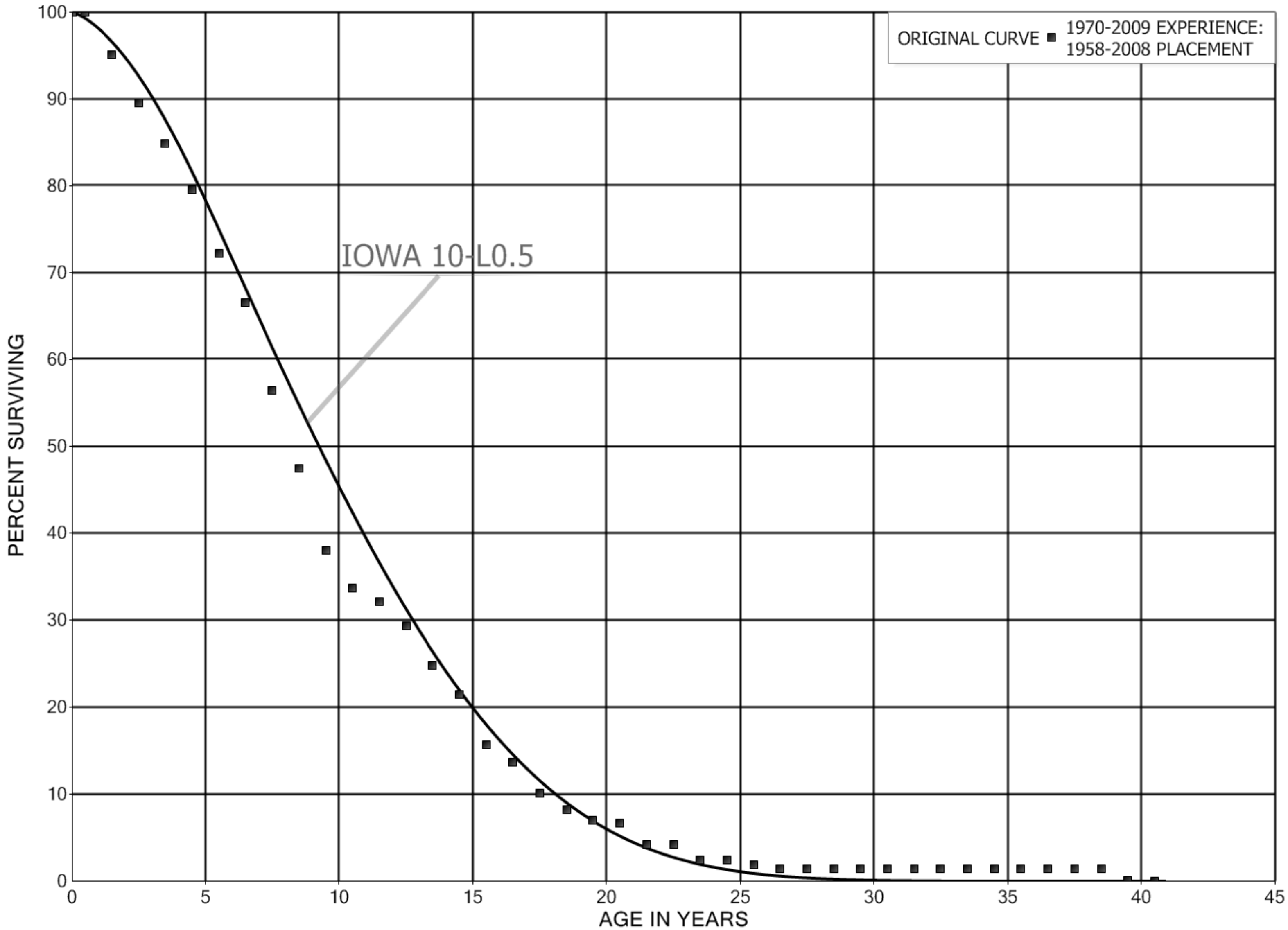
ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1962-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,167,726	339,619	0.0177	0.9823	100.00
0.5	18,682,594	3,452,073	0.1848	0.8152	98.23
1.5	15,053,894	924,559	0.0614	0.9386	80.08
2.5	14,354,037	1,474,471	0.1027	0.8973	75.16
3.5	12,810,879	2,277,560	0.1778	0.8222	67.44
4.5	10,458,915	2,447,929	0.2341	0.7659	55.45
5.5	7,962,964	1,883,021	0.2365	0.7635	42.47
6.5	6,018,280	2,216,632	0.3683	0.6317	32.43
7.5	3,737,055	1,130,134	0.3024	0.6976	20.48
8.5	2,568,417	696,959	0.2714	0.7286	14.29
9.5	1,831,490	607,011	0.3314	0.6686	10.41
10.5	1,200,025	326,996	0.2725	0.7275	6.96
11.5	823,057	270,453	0.3286	0.6714	5.06
12.5	496,561	133,758	0.2694	0.7306	3.40
13.5	299,601	83,561	0.2789	0.7211	2.48
14.5	216,040	44,020	0.2038	0.7962	1.79
15.5	172,020	27,336	0.1589	0.8411	1.43
16.5	144,684	36,543	0.2526	0.7474	1.20
17.5	108,141	10,589	0.0979	0.9021	0.90
18.5	97,552	41,165	0.4220	0.5780	0.81
19.5	56,387	10,920	0.1937	0.8063	0.47
20.5	45,467	19,252	0.4234	0.5766	0.38
21.5	26,215	1,254	0.0478	0.9522	0.22
22.5	24,961	367	0.0147	0.9853	0.21
23.5	24,594		0.0000	1.0000	0.20
24.5	24,594	3,721	0.1513	0.8487	0.20
25.5	20,873		0.0000	1.0000	0.17
26.5	20,873		0.0000	1.0000	0.17
27.5	20,873	384	0.0184	0.9816	0.17
28.5	20,489		0.0000	1.0000	0.17
29.5	20,489		0.0000	1.0000	0.17
30.5	20,489	3,441	0.1679	0.8321	0.17
31.5	17,048		0.0000	1.0000	0.14
32.5	17,048	385	0.0226	0.9774	0.14
33.5	16,663	7,823	0.4695	0.5305	0.14
34.5	8,840	8,840	1.0000		0.07
35.5					

FORTISBC ENERGY INC.
ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

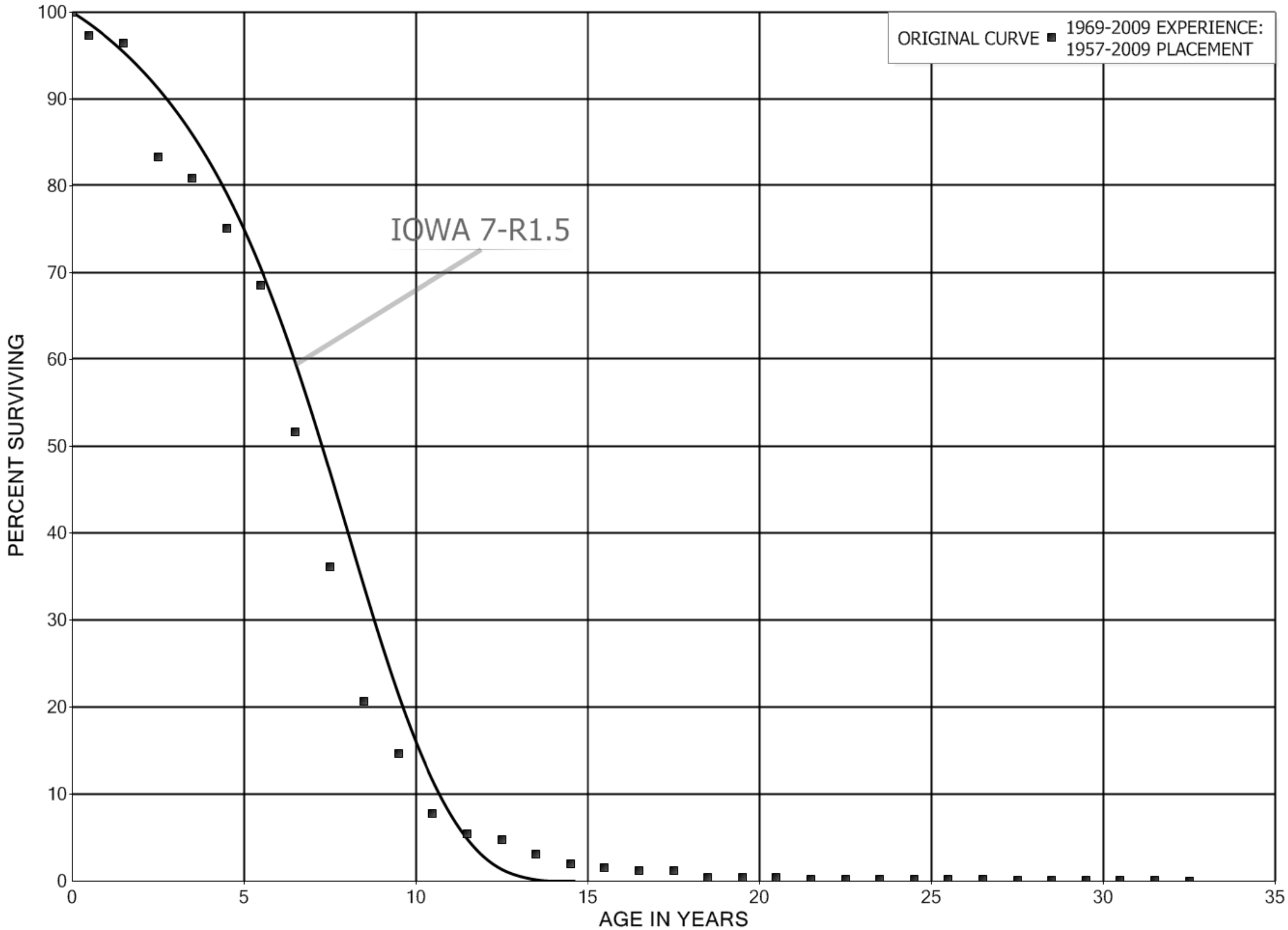
ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2008 EXPERIENCE BAND 1970-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,261,501	325	0.0003	0.9997	100.00
0.5	1,361,747	67,465	0.0495	0.9505	99.97
1.5	1,271,425	74,412	0.0585	0.9415	95.02
2.5	1,197,013	61,430	0.0513	0.9487	89.46
3.5	1,108,976	70,598	0.0637	0.9363	84.87
4.5	1,006,581	92,838	0.0922	0.9078	79.47
5.5	913,744	71,883	0.0787	0.9213	72.14
6.5	841,861	128,131	0.1522	0.8478	66.46
7.5	690,602	109,889	0.1591	0.8409	56.35
8.5	564,207	112,132	0.1987	0.8013	47.38
9.5	439,093	49,894	0.1136	0.8864	37.96
10.5	385,060	18,456	0.0479	0.9521	33.65
11.5	350,373	30,434	0.0869	0.9131	32.04
12.5	295,299	45,607	0.1544	0.8456	29.25
13.5	229,163	30,871	0.1347	0.8653	24.74
14.5	198,292	53,676	0.2707	0.7293	21.40
15.5	144,616	18,288	0.1265	0.8735	15.61
16.5	126,328	32,705	0.2589	0.7411	13.64
17.5	93,623	18,334	0.1958	0.8042	10.11
18.5	75,289	11,438	0.1519	0.8481	8.13
19.5	63,851	2,493	0.0390	0.9610	6.89
20.5	61,358	22,597	0.3683	0.6317	6.62
21.5	38,761		0.0000	1.0000	4.18
22.5	38,761	16,706	0.4310	0.5690	4.18
23.5	22,055		0.0000	1.0000	2.38
24.5	22,055	4,653	0.2110	0.7890	2.38
25.5	17,402	4,800	0.2758	0.7242	1.88
26.5	12,602		0.0000	1.0000	1.36
27.5	12,602		0.0000	1.0000	1.36
28.5	12,602		0.0000	1.0000	1.36
29.5	12,602		0.0000	1.0000	1.36
30.5	12,602		0.0000	1.0000	1.36
31.5	12,602		0.0000	1.0000	1.36
32.5	12,602		0.0000	1.0000	1.36
33.5	12,602		0.0000	1.0000	1.36
34.5	12,602		0.0000	1.0000	1.36
35.5	12,602		0.0000	1.0000	1.36
36.5	12,602		0.0000	1.0000	1.36
37.5	12,602		0.0000	1.0000	1.36
38.5	12,602	12,109	0.9609	0.0391	1.36
39.5	493	493	1.0000		0.05
40.5					

FORTISBC ENERGY INC.
ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2009 EXPERIENCE BAND 1969-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,566,466	95,257	0.0267	0.9733	100.00
0.5	3,453,458	33,718	0.0098	0.9902	97.33
1.5	3,311,647	450,545	0.1360	0.8640	96.38
2.5	2,871,823	84,272	0.0293	0.9707	83.27
3.5	2,801,327	201,105	0.0718	0.9282	80.82
4.5	2,463,863	214,821	0.0872	0.9128	75.02
5.5	2,245,205	551,801	0.2458	0.7542	68.48
6.5	1,650,668	498,677	0.3021	0.6979	51.65
7.5	1,073,812	459,036	0.4275	0.5725	36.05
8.5	587,139	170,918	0.2911	0.7089	20.64
9.5	476,963	224,202	0.4701	0.5299	14.63
10.5	277,418	86,083	0.3103	0.6897	7.75
11.5	198,672	24,538	0.1235	0.8765	5.35
12.5	174,134	60,683	0.3485	0.6515	4.69
13.5	113,451	41,190	0.3631	0.6369	3.05
14.5	72,261	16,144	0.2234	0.7766	1.94
15.5	56,117	11,951	0.2130	0.7870	1.51
16.5	44,166	1,419	0.0321	0.9679	1.19
17.5	42,747	29,983	0.7014	0.2986	1.15
18.5	12,764		0.0000	1.0000	0.34
19.5	12,764	1	0.0001	0.9999	0.34
20.5	12,763	4,280	0.3353	0.6647	0.34
21.5	8,483	1,812	0.2136	0.7864	0.23
22.5	6,671		0.0000	1.0000	0.18
23.5	6,671	323	0.0484	0.9516	0.18
24.5	6,348	1,079	0.1700	0.8300	0.17
25.5	5,269	74	0.0140	0.9860	0.14
26.5	5,195	1,509	0.2905	0.7095	0.14
27.5	3,686		0.0000	1.0000	0.10
28.5	3,686	729	0.1978	0.8022	0.10
29.5	2,957		0.0000	1.0000	0.08
30.5	2,957		0.0000	1.0000	0.08
31.5	2,957	2,957	1.0000		0.08
32.5					

PART V. NET SALVAGE STATISTICS

FORTISBC ENERGY INC.

ACCOUNT 442.00 - LNG GAS STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2006	1,959		0		0		0
2007	17,458		0		0		0
2008	6,000	2,000	33		0	2,000-	33-
2009							
TOTAL	25,417	2,000	8		0	2,000-	8-
THREE-YEAR MOVING AVERAGES							
06-08	8,472	667	8		0	667-	8-
07-09	7,819	667	9		0	667-	9-

FORTISBC ENERGY INC.

ACCOUNT 443.00 - LNG GAS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002		3,000				3,000-	
2003	12,708		0		0		0
2004							
2005							
2006	44,685		0		0		0
2007	80,648		0		0		0
2008	1,734		0		0		0
2009							
TOTAL	139,775	3,000	2		0	3,000-	2-
THREE-YEAR MOVING AVERAGES							
02-04	4,236	1,000	24		0	1,000-	24-
03-05	4,236		0		0		0
04-06	14,895		0		0		0
05-07	41,778		0		0		0
06-08	42,356		0		0		0
07-09	27,461		0		0		0
FIVE-YEAR AVERAGE							
05-09	25,413		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 449.00 - LNG GAS OTHER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	30,000		0		0		0
2002							
2003	96,616		0		0		0
2004							
2005	214,983		0		0		0
2006	111,600		0		0		0
2007	196,414		0		0		0
2008	1,297,755	283,859	22	79,166	6	204,693-	16-
2009	82,431		0		0		0
TOTAL	2,029,799	283,859	14	79,166	4	204,693-	10-
THREE-YEAR MOVING AVERAGES							
01-03	42,205		0		0		0
02-04	32,205		0		0		0
03-05	103,866		0		0		0
04-06	108,861		0		0		0
05-07	174,332		0		0		0
06-08	535,256	94,620	18	26,389	5	68,231-	13-
07-09	525,534	94,620	18	26,389	5	68,231-	13-
FIVE-YEAR AVERAGE							
05-09	380,637	56,772	15	15,833	4	40,939-	11-

FORTISBC ENERGY INC.

ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2008	13,400		0		0		0
2009	40,138		0		0		0
TOTAL	53,538		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 463.00 - TRANS. PLANT - MEAS. & REG. STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	26,672		0		0		0
2002							
2003	75,177		0		0		0
2004	86,997	15,037	17		0	15,037-	17-
2005							
2006	50,237		0		0		0
2007	40,820		0		0		0
2008							
2009	4,405		0		0		0
TOTAL	284,308	15,037	5		0	15,037-	5-
THREE-YEAR MOVING AVERAGES							
01-03	33,950		0		0		0
02-04	54,058	5,012	9		0	5,012-	9-
03-05	54,058	5,012	9		0	5,012-	9-
04-06	45,745	5,012	11		0	5,012-	11-
05-07	30,352		0		0		0
06-08	30,352		0		0		0
07-09	15,075		0		0		0
FIVE-YEAR AVERAGE							
05-09	19,092		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 464.00 - TRANS. PLANT - OTHER STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	70		0		0		0
2002							
2003		15,490				15,490-	
2004							
2005							
2006							
2007	6,746		0		0		0
2008							
2009	11,730		0		0		0
TOTAL	18,547	15,490	84		0	15,490-	84-
THREE-YEAR MOVING AVERAGES							
01-03	23	5,163			0	5,163-	
02-04		5,163				5,163-	
03-05		5,163				5,163-	
04-06							
05-07	2,249		0		0		0
06-08	2,249		0		0		0
07-09	6,159		0		0		0
FIVE-YEAR AVERAGE							
05-09	3,695		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	719		0		0		0
2001	1,219,906		0		0		0
2002	657,746	5,259	1		0	5,259-	1-
2003	1,850,075		0		0		0
2004	682,967	80,507	12		0	80,507-	12-
2005	749,466	36,935	5		0	36,935-	5-
2006	576,912	7,635	1		0	7,635-	1-
2007	124,402		0		0		0
2008	67,495	47,528	70		0	47,528-	70-
2009	703,198	752,187	107		0	752,187-	107-
TOTAL	6,632,888	930,050	14		0	930,050-	14-
THREE-YEAR MOVING AVERAGES							
00-02	626,124	1,753	0		0	1,753-	0
01-03	1,242,576	1,753	0		0	1,753-	0
02-04	1,063,596	28,589	3		0	28,589-	3-
03-05	1,094,169	39,147	4		0	39,147-	4-
04-06	669,782	41,692	6		0	41,692-	6-
05-07	483,593	14,857	3		0	14,857-	3-
06-08	256,270	18,388	7		0	18,388-	7-
07-09	298,365	266,572	89		0	266,572-	89-
FIVE-YEAR AVERAGE							
05-09	444,295	168,857	38		0	168,857-	38-

FORTISBC ENERGY INC.

ACCOUNT 466.00 - TRANS. PLANT - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	10,826		0		0		0
2002							
2003	57,131	12,923	23		0	12,923-	23-
2004		2,000				2,000-	
2005	67,044		0		0		0
2006							
2007							
2008	62,641	3,523	6		0	3,523-	6-
2009		19,228				19,228-	
TOTAL	197,641	37,674	19		0	37,674-	19-
THREE-YEAR MOVING AVERAGES							
01-03	22,652	4,308	19		0	4,308-	19-
02-04	19,044	4,974	26		0	4,974-	26-
03-05	41,392	4,974	12		0	4,974-	12-
04-06	22,348	667	3		0	667-	3-
05-07	22,348		0		0		0
06-08	20,880	1,174	6		0	1,174-	6-
07-09	20,880	7,584	36		0	7,584-	36-
FIVE-YEAR AVERAGE							
05-09	25,937	4,550	18		0	4,550-	18-

FORTISBC ENERGY INC.

ACCOUNT 467.10 - TRANS. PLANT - MEAS. & REG. EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	251,311		0		0		0
2002	178,402		0		0		0
2003	309,532		0		0		0
2004	1,928,908	77,340	4		0	77,340-	4-
2005	139,586	9,763	7		0	9,763-	7-
2006	206,490	47,392	23		0	47,392-	23-
2007	275,309		0		0		0
2008	26,600	6,720	25		0	6,720-	25-
2009	231,628	2,015	1		0	2,015-	1-
TOTAL	3,547,768	143,230	4		0	143,230-	4-
THREE-YEAR MOVING AVERAGES							
01-03	246,415		0		0		0
02-04	805,614	25,780	3		0	25,780-	3-
03-05	792,675	29,034	4		0	29,034-	4-
04-06	758,328	44,831	6		0	44,831-	6-
05-07	207,129	19,052	9		0	19,052-	9-
06-08	169,466	18,037	11		0	18,037-	11-
07-09	177,846	2,912	2		0	2,912-	2-
FIVE-YEAR AVERAGE							
05-09	175,923	13,178	7		0	13,178-	7-

FORTISBC ENERGY INC.

ACCOUNT 472.00 - DIST. SYSTEM - STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	13,168		0		0		0
2001	104,190		0		0		0
2002	40,060		0		0		0
2003	78,668		0		0		0
2004	953		0		0		0
2005		3,678				3,678-	
2006	50,994	4,276	8		0	4,276-	8-
2007	54,535		0		0		0
2008	80,293	26,516	33		0	26,516-	33-
2009	35,094	39,152	112		0	39,152-	112-
TOTAL	457,955	73,623	16		0	73,623-	16-
THREE-YEAR MOVING AVERAGES							
00-02	52,473		0		0		0
01-03	74,306		0		0		0
02-04	39,894		0		0		0
03-05	26,540	1,226	5		0	1,226-	5-
04-06	17,316	2,652	15		0	2,652-	15-
05-07	35,176	2,652	8		0	2,652-	8-
06-08	61,941	10,264	17		0	10,264-	17-
07-09	56,641	21,889	39		0	21,889-	39-
FIVE-YEAR AVERAGE							
05-09	44,183	14,725	33		0	14,725-	33-

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DIST. SYSTEM - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	1,800,475		0		0		0
2001	1,098,971		0		0		0
2002	2,424,745	588,456	24		0	588,456-	24-
2003	329,949	211,987	64		0	211,987-	64-
2004	2,307,982	3,531,097	153		0	3,531,097-	153-
2005	2,397,190	3,551,042	148		0	3,551,042-	148-
2006	13,094,973	1,630,153	12		0	1,630,153-	12-
2007	9,076,825		0		0		0
2008	3,628,625	5,404,860	149		0	5,404,860-	149-
2009	4,266,681	5,440,566	128		0	5,440,566-	128-
TOTAL	40,426,416	20,358,162	50		0	20,358,162-	50-
THREE-YEAR MOVING AVERAGES							
00-02	1,774,730	196,152	11		0	196,152-	11-
01-03	1,284,555	266,814	21		0	266,814-	21-
02-04	1,687,558	1,443,847	86		0	1,443,847-	86-
03-05	1,678,374	2,431,375	145		0	2,431,375-	145-
04-06	5,933,382	2,904,098	49		0	2,904,098-	49-
05-07	8,189,663	1,727,065	21		0	1,727,065-	21-
06-08	8,600,141	2,345,004	27		0	2,345,004-	27-
07-09	5,657,377	3,615,142	64		0	3,615,142-	64-
FIVE-YEAR AVERAGE							
05-09	6,492,859	3,205,324	49		0	3,205,324-	49-

FORTISBC ENERGY INC.

ACCOUNT 473.01 - LILO DIST. SYSTEM - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2002	50,047		0		0		0
2003	13,262		0		0		0
2004	24,860		0		0		0
2005	88,506		0		0		0
2006	69,978		0		0		0
2007	63,250		0		0		0
2008	73,430		0		0		0
2009	52,540		0		0		0
TOTAL	435,873		0		0		0
THREE-YEAR MOVING AVERAGES							
02-04	29,390		0		0		0
03-05	42,209		0		0		0
04-06	61,115		0		0		0
05-07	73,911		0		0		0
06-08	68,886		0		0		0
07-09	63,073		0		0		0
FIVE-YEAR AVERAGE							
05-09	69,541		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 474.00 - DIST. SYSTEM - METERS/REG. INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	95,683		0		0		0
2001	2,428,481		0		0		0
2002	6,270,257	53,023	1		0	53,023-	1-
2003	3,267,469	14,989	0		0	14,989-	0
2004	4,930,968	247,468	5		0	247,468-	5-
2005	6,813,560	217,139	3		0	217,139-	3-
2006	8,240,670	211,256	3		0	211,256-	3-
2007	5,860,519		0		0		0
2008	7,010,448	900,663	13		0	900,663-	13-
2009	7,349,546	1,320,731	18	12,236	0	1,308,495-	18-
TOTAL	52,267,601	2,965,269	6	12,236	0	2,953,032-	6-
THREE-YEAR MOVING AVERAGES							
00-02	2,931,474	17,674	1		0	17,674-	1-
01-03	3,988,736	22,671	1		0	22,671-	1-
02-04	4,822,898	105,160	2		0	105,160-	2-
03-05	5,003,999	159,865	3		0	159,865-	3-
04-06	6,661,733	225,288	3		0	225,288-	3-
05-07	6,971,583	142,798	2		0	142,798-	2-
06-08	7,037,212	370,640	5		0	370,640-	5-
07-09	6,740,171	740,464	11	4,079	0	736,386-	11-
FIVE-YEAR AVERAGE							
05-09	7,054,949	529,958	8	2,447	0	527,510-	7-

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DIST. SYSTEMS - MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	4,430,340		0		0		0
2001	485,250		0		0		0
2002	998,123	63,210	6		0	63,210-	6-
2003	88,626	23,024	26		0	23,024-	26-
2004	408,796	364,611	89		0	364,611-	89-
2005	810,205	532,849	66		0	532,849-	66-
2006	2,667,611	139,634	5		0	139,634-	5-
2007	2,127,563		0		0		0
2008	2,405,264	474,834	20		0	474,834-	20-
2009	3,348,332	592,027	18		0	592,027-	18-
TOTAL	17,770,109	2,190,189	12		0	2,190,189-	12-
THREE-YEAR MOVING AVERAGES							
00-02	1,971,238	21,070	1		0	21,070-	1-
01-03	524,000	28,745	5		0	28,745-	5-
02-04	498,515	150,282	30		0	150,282-	30-
03-05	435,876	306,828	70		0	306,828-	70-
04-06	1,295,537	345,698	27		0	345,698-	27-
05-07	1,868,459	224,161	12		0	224,161-	12-
06-08	2,400,146	204,823	9		0	204,823-	9-
07-09	2,627,053	355,620	14		0	355,620-	14-
FIVE-YEAR AVERAGE							
05-09	2,271,795	347,869	15		0	347,869-	15-

FORTISBC ENERGY INC.

ACCOUNT 475.01 - LILO DIST. SYSTEM - MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	2,112		0		0		0
2003	7,601		0		0		0
2004	16,069		0		0		0
2005	5,928		0		0		0
2006	34,231		0		0		0
2007	35,872		0		0		0
2008	39,188		0		0		0
2009	2,624		0		0		0
TOTAL	143,626		0		0		0
THREE-YEAR MOVING AVERAGES							
02-04	8,594		0		0		0
03-05	9,866		0		0		0
04-06	18,743		0		0		0
05-07	25,344		0		0		0
06-08	36,430		0		0		0
07-09	25,895		0		0		0
FIVE-YEAR AVERAGE							
05-09	23,569		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 476.00 - DIST. SYSTEM - NGV FUEL EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	7,475,766		0		0		0
2001	91		0		0		0
2002							
2003							
2004							
2005							
2006							
2007							
2008							
2009							
TOTAL	7,475,857		0		0		0
THREE-YEAR MOVING AVERAGES							
00-02	2,491,952		0		0		0
01-03	30		0		0		0
02-04							
03-05							
04-06							
05-07							
06-08							
07-09							
FIVE-YEAR AVERAGE							
05-09							

FORTISBC ENERGY INC.

ACCOUNT 477.30 - DIST. SYSTEM - MEAS. & REG. EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2002	18,026		0		0		0
2003							
2004							
2005							
2006							
2007							
2008							
2009							
TOTAL	18,026		0		0		0
THREE-YEAR MOVING AVERAGES							
02-04	6,009		0		0		0
03-05							
04-06							
05-07							
06-08							
07-09							
FIVE-YEAR AVERAGE							
05-09							

FORTISBC ENERGY INC.

ACCOUNT 478.10 - DIST. SYSTEM - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	418,424		0		0		0
2001	2,284,414		0		0		0
2002	3,531,074		0		0		0
2003	2,018,918		0		0		0
2004	2,729,515		0	78,811	3	78,811	3
2005	4,879,690		0		0		0
2006	3,916,552		0		0		0
2007	3,022,852		0		0		0
2008	4,782,171	69,432-	1-	284,774	6	354,206	7
2009	4,143,930	71,292	2	66,136	2	5,156-	0
TOTAL	31,727,540	1,860	0	429,721	1	427,861	1
THREE-YEAR MOVING AVERAGES							
00-02	2,077,971		0		0		0
01-03	2,611,469		0		0		0
02-04	2,759,836		0	26,270	1	26,270	1
03-05	3,209,374		0	26,270	1	26,270	1
04-06	3,841,919		0	26,270	1	26,270	1
05-07	3,939,698		0		0		0
06-08	3,907,192	23,144-	1-	94,925	2	118,069	3
07-09	3,982,984	620	0	116,970	3	116,350	3
FIVE-YEAR AVERAGE							
05-09	4,149,039	372	0	70,182	2	69,810	2

PART VI. DETAILED DEPRECIATION CALCULATIONS

FORTISBC ENERGY INC.

ACCOUNT 401.01 - FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1959	2,931.00	2,858	1,474	1,457	1.00	1,457
1960	88,488.00	86,276	44,498	43,990	1.00	43,990
1962	4,804.00	4,684	2,416	2,388	1.00	2,388
1963	230.00	224	116	114	1.00	114
1964	50.00	49	25	25	1.00	25
1969	848.00	827	426	422	1.00	422
1970	452.00	441	227	225	1.00	225
1971	260.00	247	127	133	2.00	66
1972	300.00	278	144	156	3.00	52
1973	50.00	45	23	27	4.00	7
1976	823.00	679	351	472	7.00	67
	99,236.00	96,608	49,827	49,409		48,813

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 1.0   49.19

FORTISBC ENERGY INC.

ACCOUNT 402.03 - INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2001	687,554.78	137,511	164,879	522,676	32.00	16,334
	687,554.78	137,511	164,879	522,676		16,334

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 32.0 2.38

FORTISBC ENERGY INC.

ACCOUNT 402.11 - INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE NET SALVAGE PERCENT.. 0						
1970	62,456.53	60,895	26,771	35,686	1.00	35,686
	62,456.53	60,895	26,771	35,686		35,686

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 1.0 57.14

FORTISBC ENERGY INC.

ACCOUNT 432.00 - MFG. GAS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	358,775.13	170,418	90,129	268,646	21.00	12,793
1992	1,967.78	836	442	1,526	23.00	66
1996	899.39	292	154	745	27.00	28
1997	3,664.53	1,099	581	3,084	28.00	110
1998	2,668.96	734	388	2,281	29.00	79
1999	6,436.48	1,609	851	5,585	30.00	186
2000	13,624.40	3,065	1,621	12,003	31.00	387
2001	1,019.52	204	108	912	32.00	28
2002	47,817.40	8,368	4,426	43,391	33.00	1,315
2004	437.00	55	29	408	35.00	12
2005	11,641.25	1,164	616	11,025	36.00	306
2006	1,293.03	97	51	1,242	37.00	34
2007	666.81	33	17	650	38.00	17
2008	12,597.36	315	167	12,430	39.00	319
2009	0.95	0	0	1		
	463,509.99	188,289	99,580	363,930		15,680

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 23.2   3.38

FORTISBC ENERGY INC.

ACCOUNT 433.00 - MFG. GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	5,018.55	3,764	2,635	2,384	5.00	477
1996	3,868.62	2,515	1,761	2,108	7.00	301
1997	13,895.12	8,337	5,836	8,059	8.00	1,007
1999	108,001.17	54,001	37,801	70,200	10.00	7,020
2000	5,687.97	2,560	1,792	3,896	11.00	354
2002	3,008.60	1,053	737	2,272	13.00	175
2005	6,458.40	1,292	904	5,554	16.00	347
	145,938.43	73,522	51,466	94,472		9,681

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 9.8 6.63

FORTISBC ENERGY INC.

ACCOUNT 434.00 - MFG. GAS HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	239,942.82	113,973	122,434	117,509	21.00	5,596
1992	103,238.92	43,877	47,134	56,105	23.00	2,439
1996	860.87	280	301	560	27.00	21
1997	763.37	229	246	517	28.00	18
1998	680.66	187	201	480	29.00	17
1999	681.40	170	183	498	30.00	17
2000	544.40	122	131	413	31.00	13
2001	10,282.20	2,056	2,208	8,074	32.00	252
2002	590.33	103	111	479	33.00	15
	357,584.97	160,997	172,949	184,636		8,388

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 22.0 2.35

FORTISBC ENERGY INC.

ACCOUNT 436.00 - MFG. GAS COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	1,382.72	940	729	654	8.00	82
1995	51,926.19	29,079	22,542	29,384	11.00	2,671
	53,308.91	30,019	23,271	30,038		2,753

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 10.9 5.16

FORTISBC ENERGY INC.

ACCOUNT 437.00 - MFG. GAS MEASURING & REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	290,389.70	246,831	147,019	143,371	3.00	47,790
1994	4,011.82	3,009	1,792	2,220	5.00	444
1996	789.15	513	306	483	7.00	69
1997	699.77	420	250	450	8.00	56
1998	623.95	343	204	420	9.00	47
1999	624.63	312	186	439	10.00	44
2000	499.05	225	134	365	11.00	33
2001	1,086.26	435	259	827	12.00	69
2002	541.14	189	113	428	13.00	33
2003	10,181.08	3,054	1,819	8,362	14.00	597
	309,446.55	255,331	152,082	157,365		49,182

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 3.2 15.89

FORTISBC ENERGY INC.

ACCOUNT 442.00 - LNG GAS STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L2						
NET SALVAGE PERCENT.. 0						
1988	1,453,071.43	829,413	956,611	496,460	10.73	46,268
1991	1,924.79	1,028	1,186	739	11.65	63
1992	110,426.95	57,334	66,127	44,300	12.02	3,686
1993	8,093.70	4,073	4,698	3,396	12.42	273
1994	84,561.94	41,029	47,321	37,241	12.87	2,894
1995	132,581.49	61,624	71,075	61,506	13.38	4,597
1996	42,779.92	18,943	21,848	20,932	13.93	1,503
1997	246,113.24	102,875	118,652	127,461	14.55	8,760
1998	396,745.70	155,048	178,826	217,920	15.23	14,309
1999	133,892.83	48,416	55,841	78,052	15.96	4,890
2000	318,749.06	105,315	121,466	197,283	16.74	11,785
2001	94,819.16	28,218	32,545	62,274	17.56	3,546
2002	36,534.09	9,645	11,124	25,410	18.40	1,381
2003	704,255.73	161,415	186,169	518,087	19.27	26,886
2004	16,996.28	3,284	3,788	13,208	20.17	655
2005	788,457.87	123,315	142,226	646,232	21.09	30,642
2006	13,612.01	1,612	1,859	11,753	22.04	533
2007	270,602.22	21,540	24,844	245,758	23.01	10,680
2008	30,361.26	1,214	1,400	28,961	24.00	1,207
2009	0.84	0	0	1		
	4,884,580.51	1,775,341	2,047,606	2,836,975		174,558

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 16.3   3.57

FORTISBC ENERGY INC.

ACCOUNT 443.00 - LNG GAS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-L4						
NET SALVAGE PERCENT.. 0						
1988	9,052,020.29	4,675,368	6,187,719	2,864,301	19.34	148,102
1991	29,946.64	13,386	17,716	12,231	22.12	553
1993	62,452.26	24,903	32,958	29,494	24.05	1,226
1996	393,472.04	127,878	169,243	224,229	27.00	8,305
1997	184,604.19	55,381	73,295	111,309	28.00	3,975
1998	102,424.92	28,167	37,278	65,147	29.00	2,246
1999	746,733.77	186,683	247,070	499,664	30.00	16,655
2000	81,921.07	18,432	24,394	57,527	31.00	1,856
2001	102,295.11	20,459	27,077	75,218	32.00	2,351
2002	5,304,069.89	928,212	1,228,464	4,075,606	33.00	123,503
2003	183,540.37	27,531	36,436	147,104	34.00	4,327
2004	198,778.25	24,847	32,885	165,893	35.00	4,740
2006	51,498.10	3,862	5,111	46,387	37.00	1,254
2007	260.44	13	17	243	38.00	6
	16,494,017.34	6,135,122	8,119,663	8,374,354		319,099

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 26.2 1.93

FORTISBC ENERGY INC.

ACCOUNT 449.00 - LNG GAS OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-R3						
NET SALVAGE PERCENT.. 0						
1988	5,536,937.17	3,715,894	3,116,556	2,420,381	8.88	272,565
1991	554,462.83	328,774	275,746	278,717	10.99	25,361
1992	562,926.89	318,161	266,845	296,082	11.74	25,220
1993	2,336,891.81	1,254,140	1,051,859	1,285,033	12.51	102,720
1994	195,647.09	99,273	83,261	112,386	13.30	8,450
1995	2,871,517.51	1,370,891	1,149,779	1,721,739	14.11	122,023
1996	801,912.30	358,190	300,417	501,495	14.94	33,567
1997	81,130.05	33,684	28,251	52,879	15.79	3,349
1998	18,560.60	7,115	5,967	12,594	16.65	756
1999	649,297.54	227,735	191,004	458,294	17.53	26,143
2000	964,847.19	306,252	256,857	707,990	18.43	38,415
2001	21,505.53	6,101	5,117	16,389	19.34	847
2002	357,001.87	89,118	74,744	282,258	20.26	13,932
2003	1,799,856.75	386,627	324,268	1,475,589	21.20	69,603
2004	32,356.13	5,812	4,875	27,481	22.15	1,241
2005	198,987.18	28,742	24,106	174,881	23.10	7,571
2006	305,886.62	33,195	27,841	278,046	24.07	11,552
2007	359,087.89	26,066	21,862	337,226	25.04	13,467
2008	4,157,417.12	150,914	126,572	4,030,845	26.02	154,913
2009	1,170,792.04	0	0	1,170,792	27.00	43,363
	22,977,022.11	8,746,684	7,335,927	15,641,095		975,058

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 16.0   4.24

FORTISBC ENERGY INC.

ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. 0						
1973	215,401.10	198,886	170,490	44,911	2.30	19,527
1975	6,158.28	5,567	4,772	1,386	2.88	481
1977	67.03	59	51	16	3.56	4
1978	5,916.53	5,138	4,404	1,513	3.95	383
1980	614.64	515	441	174	4.88	36
1982	1,246.15	996	854	392	6.03	65
1984	895.28	676	579	316	7.34	43
1988	2,555.92	1,682	1,442	1,114	10.26	109
1989	2,559.08	1,616	1,385	1,174	11.05	106
1990	31,298.71	18,915	16,214	15,085	11.87	1,271
1991	12,958.63	7,468	6,402	6,557	12.71	516
1992	180,650.89	98,937	84,811	95,840	13.57	7,063
1993	1,176,261.65	609,304	522,311	653,951	14.46	45,225
1994	1,481,778.17	723,108	619,867	861,911	15.36	56,114
1995	4,624,628.27	2,114,981	1,813,016	2,811,612	16.28	172,703
1996	434,474.21	185,229	158,783	275,691	17.21	16,019
1997	301,943.37	119,168	102,154	199,789	18.16	11,002
1998	80,989.13	29,372	25,178	55,811	19.12	2,919
1999	24,713.22	8,164	6,998	17,715	20.09	882
2000	3,717,798.45	1,107,904	949,724	2,768,074	21.06	131,438
2001	785,504.38	208,418	178,661	606,843	22.04	27,534
2002	1,122,673.38	260,831	223,591	899,082	23.03	39,040
2003	100,279.43	19,989	17,135	83,144	24.02	3,461
2004	139,535.03	23,209	19,895	119,640	25.01	4,784
2006	27,389.06	2,739	2,348	25,041	27.00	927
2007	49,912.12	3,328	2,853	47,059	28.00	1,681
2008	95,014.95	3,167	2,715	92,300	29.00	3,183
2009	57,481.45	0	0	57,481	30.00	1,916
9999	25,103.07	9,848	8,442	16,661		938
	14,705,801.58	5,769,214	4,945,516	9,760,286		549,370

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 17.8 3.74

FORTISBC ENERGY INC.

ACCOUNT 463.00 - TRANS. PLANT - MEAS. & REG. STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 30-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1972	30,628.34	23,553	17,681	12,947	6.93	1,868
1974	12,536.32	9,335	7,008	5,528	7.66	722
1980	1,662.26	1,105	830	832	10.05	83
1982	1,246.15	792	595	651	10.93	60
1984	8,916.23	5,394	4,049	4,867	11.85	411
1985	3,043.26	1,791	1,344	1,699	12.34	138
1986	1,364.56	781	586	779	12.83	61
1987	8,403.96	4,667	3,503	4,901	13.34	367
1988	188,882.31	101,556	76,238	112,644	13.87	8,121
1989	1,902.24	989	742	1,160	14.41	80
1990	5,248.61	2,630	1,974	3,275	14.97	219
1991	795,810.16	383,318	287,755	508,055	15.55	32,672
1992	261,654.07	120,884	90,747	170,907	16.14	10,589
1993	174,055.32	76,816	57,665	116,390	16.76	6,945
1994	71,195.96	29,902	22,447	48,749	17.40	2,802
1995	472,438.09	188,030	141,153	331,285	18.06	18,344
1996	345,954.76	129,733	97,390	248,565	18.75	13,257
1997	146,210.80	51,368	38,562	107,649	19.46	5,532
1998	68,521.07	22,406	16,820	51,701	20.19	2,561
1999	93,361.29	28,164	21,143	72,218	20.95	3,447
2000	367,640.99	101,223	75,988	291,653	21.74	13,416
2001	105,861.23	26,254	19,709	86,152	22.56	3,819
2002	773,942.06	170,267	127,819	646,123	23.40	27,612
2003	203,594.88	38,887	29,192	174,403	24.27	7,186
2004	366,262.99	58,968	44,267	321,996	25.17	12,793
2005	154,564.20	20,144	15,122	139,442	26.09	5,345
2006	93,171.43	9,193	6,901	86,270	27.04	3,190
2007	18,360.22	1,218	914	17,446	28.01	623
2008	27,844.35	928	697	27,147	29.00	936
2009	189,289.94	0	0	189,290	30.00	6,310
	4,993,568.05	1,610,296	1,208,841	3,784,727		189,509

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 20.0   3.80

FORTISBC ENERGY INC.

ACCOUNT 464.00 - TRANS. PLANT - OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 35-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	7,845.44	6,364	6,542	1,303	6.61	197
1975	1,992.26	1,563	1,607	385	7.54	51
1978	6,315.00	4,662	4,792	1,523	9.16	166
1979	10,826.17	7,810	8,028	2,798	9.75	287
1983	8,868.78	5,744	5,904	2,965	12.33	240
1984	3,199.30	2,008	2,064	1,135	13.03	87
1987	18,636.05	10,521	10,815	7,821	15.24	513
1988	12,898.76	6,998	7,193	5,706	16.01	356
1989	5,246.07	2,728	2,804	2,442	16.80	145
1990	4,177.22	2,077	2,135	2,042	17.60	116
1991	26,130.83	12,386	12,732	13,399	18.41	728
1993	9,555.00	4,070	4,184	5,371	20.09	267
1994	43,742.33	17,572	18,063	25,679	20.94	1,226
1995	565.90	213	219	347	21.81	16
1996	76,883.05	27,019	27,774	49,109	22.70	2,163
1997	17,012.33	5,546	5,701	11,311	23.59	479
1998	3,010.54	903	928	2,083	24.50	85
1999	191,806.97	52,555	54,023	137,784	25.41	5,422
2000	105,424.54	26,085	26,814	78,611	26.34	2,984
2001	3,833,288.66	846,620	870,267	2,963,022	27.27	108,655
2002	537,707.52	104,159	107,068	430,640	28.22	15,260
2003	10,828.76	1,804	1,854	8,975	29.17	308
2004	521,633.26	72,580	74,608	447,025	30.13	14,837
2005	194,716.26	21,752	22,359	172,357	31.09	5,544
2006	236,208.58	19,842	20,397	215,812	32.06	6,732
2007	104,353.28	5,844	6,007	98,346	33.04	2,977
2008	163.42	5	5	158	34.02	5
2009	15,165.02	0	0	15,165	35.00	433
	6,008,201.30	1,269,430	1,304,887	4,703,314		170,279

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 27.6 2.83

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1957	14,799.95	10,151	12,611	2,189	20.42	107
1958	12,798,077.18	8,647,533	10,742,988	2,055,089	21.08	97,490
1959	1,388,481.82	924,090	1,148,014	240,468	21.74	11,061
1960	17,607.69	11,534	14,329	3,279	22.42	146
1961	133,268.62	85,886	106,698	26,571	23.11	1,150
1962	2,427,253.70	1,538,515	1,911,325	515,929	23.80	21,678
1963	92,529.62	57,639	71,606	20,924	24.51	854
1964	61,509.66	37,635	46,755	14,755	25.23	585
1966	267,995.64	157,911	196,176	71,820	26.70	2,690
1967	475,284.04	274,643	341,194	134,090	27.44	4,887
1968	769,109.24	435,431	540,944	228,165	28.20	8,091
1969	1,619,375.27	897,879	1,115,451	503,924	28.96	17,401
1970	363,907.47	197,405	245,240	118,667	29.74	3,990
1971	2,329,357.10	1,235,631	1,535,047	794,310	30.52	26,026
1972	7,749,649.31	4,016,721	4,990,046	2,759,603	31.31	88,138
1973	409,455.57	207,185	257,390	152,066	32.11	4,736
1974	32,703.80	16,146	20,058	12,646	32.91	384
1975	64,059.91	30,818	38,286	25,774	33.73	764
1976	18,231,916.30	8,540,924	10,610,546	7,621,370	34.55	220,590
1977	394,718.34	179,869	223,455	171,263	35.38	4,841
1978	350,257.34	155,083	192,662	157,595	36.22	4,351
1979	88,271.44	37,943	47,137	41,134	37.06	1,110
1980	750,047.89	312,485	388,206	361,842	37.92	9,542
1981	1,381,809.57	557,615	692,735	689,075	38.77	17,773
1982	688,524.67	268,628	333,721	354,804	39.64	8,951
1983	353,687.81	133,259	165,550	188,138	40.51	4,644
1984	484,286.28	175,907	218,532	265,754	41.39	6,421
1985	1,078,062.44	376,826	468,138	609,924	42.28	14,426
1986	3,711,834.06	1,246,619	1,548,698	2,163,136	43.17	50,107
1987	1,898,411.79	611,289	759,416	1,138,996	44.07	25,845
1988	41,090,280.27	12,661,970	15,730,197	25,360,083	44.97	563,933
1989	694,593.57	204,315	253,824	440,770	45.88	9,607
1990	6,656,592.02	1,863,846	2,315,490	4,341,102	46.80	92,759
1991	3,219,375.21	855,871	1,063,264	2,156,111	47.72	45,183
1992	54,910,624.98	13,812,219	17,159,172	37,751,453	48.65	775,981
1993	6,470,415.80	1,534,977	1,906,930	4,563,486	49.58	92,043
1994	2,922,275.08	650,995	808,743	2,113,532	50.52	41,836
1995	33,125,208.82	6,900,312	8,572,384	24,552,825	51.46	477,124
1996	12,592,678.39	2,441,091	3,032,612	9,560,066	52.40	182,444
1997	9,738,575.86	1,745,445	2,168,398	7,570,178	53.35	141,896
1998	16,417,056.95	2,699,949	3,354,196	13,062,861	54.31	240,524
1999	12,275,399.29	1,839,469	2,285,206	9,990,193	55.26	180,785
2000	319,021,086.22	43,093,368	53,535,679	265,485,407	56.22	4,722,259
2001	45,484,387.24	5,464,949	6,789,206	38,695,181	57.19	676,607
2002	23,343,037.17	2,456,388	3,051,616	20,291,421	58.16	348,890
2003	17,248,589.35	1,557,720	1,935,184	15,313,405	59.13	258,979

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
2004	12,948,336.18	976,046	1,212,560	11,735,776	60.10	195,271
2005	9,209,844.73	556,827	691,756	8,518,089	61.07	139,481
2006	9,301,387.22	422,097	524,379	8,777,008	62.05	141,451
2007	6,290,345.79	190,660	236,861	6,053,485	63.03	96,041
2008	11,046,394.53	166,580	206,945	10,839,450	64.02	169,313
2009	5,532,643.21	0	0	5,532,643	65.00	85,118
	719,965,381.40	133,474,294	165,817,556	554,147,825		10,336,304

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 53.6 1.44

FORTISBC ENERGY INC.

ACCOUNT 466.00 - TRANS. PLANT - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1973	1,194,018.18	968,516	956,644	237,374	6.61	35,911
1974	288,030.63	229,932	227,114	60,917	7.06	8,628
1975	2,752.84	2,160	2,134	619	7.54	82
1976	12,388.65	9,536	9,419	2,970	8.06	368
1977	49,027.94	36,995	36,542	12,486	8.59	1,454
1978	778,072.63	574,443	567,402	210,671	9.16	22,999
1979	2,841.36	2,050	2,025	816	9.75	84
1981	3,009.83	2,064	2,039	971	11.00	88
1983	31,042.02	20,106	19,860	11,182	12.33	907
1984	3,474.57	2,181	2,154	1,321	13.03	101
1985	1,287.81	782	772	516	13.75	38
1986	7,609.26	4,459	4,404	3,205	14.49	221
1987	87,594.98	49,453	48,847	38,748	15.24	2,543
1988	13,505.80	7,328	7,238	6,268	16.01	392
1989	20,082.21	10,443	10,315	9,767	16.80	581
1990	30,473.35	15,150	14,964	15,509	17.60	881
1991	17,686.64	8,383	8,280	9,407	18.41	511
1992	2,162,719.98	973,851	961,914	1,200,806	19.24	62,412
1993	4,756,897.96	2,026,439	2,001,599	2,755,299	20.09	137,148
1994	21,030,612.77	8,448,207	8,344,650	12,685,963	20.94	605,824
1995	4,704,619.85	1,772,983	1,751,250	2,953,370	21.81	135,414
1996	1,430,877.06	502,853	496,689	934,188	22.70	41,154
1997	2,324,986.10	757,945	748,654	1,576,332	23.59	66,822
1998	301,949.00	90,585	89,475	212,474	24.50	8,672
1999	169,782.03	46,520	45,950	123,832	25.41	4,873
2000	50,810,101.93	12,571,944	12,417,839	38,392,263	26.34	1,457,565
2001	5,536,988.85	1,222,899	1,207,909	4,329,080	27.27	158,749
2002	6,423,568.02	1,244,309	1,229,056	5,194,512	28.22	184,072
2003	804,232.30	133,961	132,319	671,913	29.17	23,034
2004	2,373,658.09	330,271	326,223	2,047,435	30.13	67,953
2005	245,366.09	27,410	27,074	218,292	31.09	7,021
2006	11,647.80	978	966	10,682	32.06	333
2007	23,262.07	1,303	1,287	21,975	33.04	665
2008	431,426.82	12,080	11,932	419,495	34.02	12,331
2009	175,072.07	0	0	175,072	35.00	5,002
	106,260,667.49	32,108,519	31,714,939	74,545,728		3,054,833

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 24.4   2.87

FORTISBC ENERGY INC.

ACCOUNT 467.10 - TRANS. PLANT - MEAS. & REG. EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-L1						
NET SALVAGE PERCENT.. 0						
1971	52,395.12	33,960	21,625	30,770	9.50	3,239
1972	125,694.32	80,258	51,107	74,587	9.76	7,642
1974	16,590.56	10,262	6,535	10,056	10.30	976
1975	998.36	608	387	611	10.57	58
1977	1,038.54	610	388	651	11.14	58
1978	3,487.48	2,011	1,281	2,206	11.43	193
1981	1,834.03	996	634	1,200	12.33	97
1982	15,188.66	8,078	5,144	10,045	12.64	795
1984	28,053.01	14,245	9,071	18,982	13.29	1,428
1985	107,429.56	53,238	33,901	73,529	13.62	5,399
1986	37,810.22	18,275	11,637	26,173	13.95	1,876
1987	19,837.99	9,331	5,942	13,896	14.30	972
1988	1,302,795.54	595,912	379,466	923,330	14.65	63,026
1989	57,162.09	25,384	16,164	40,998	15.01	2,731
1990	1,476.80	636	405	1,072	15.37	70
1991	1,402,451.18	584,878	372,440	1,030,011	15.74	65,439
1992	1,626,516.50	655,421	417,361	1,209,156	16.12	75,010
1993	1,473,196.57	572,366	364,473	1,108,724	16.51	67,155
1994	903,226.16	337,536	214,937	688,289	16.91	40,703
1995	1,573,788.09	563,652	358,924	1,214,864	17.33	70,102
1996	978,197.18	334,397	212,938	765,259	17.77	43,065
1997	2,994,427.24	971,512	618,642	2,375,785	18.24	130,251
1998	420,828.55	128,744	81,982	338,847	18.74	18,081
1999	394,751.64	112,871	71,874	322,878	19.28	16,747
2000	3,952,644.10	1,043,775	664,658	3,287,986	19.87	165,475
2001	984,386.72	236,981	150,905	833,482	20.50	40,658
2002	2,081,627.66	449,486	286,225	1,795,403	21.17	84,809
2003	4,141,799.89	785,410	500,136	3,641,664	21.88	166,438
2004	720,435.38	116,336	74,081	646,354	22.64	28,549
2005	282,164.95	37,203	23,690	258,475	23.44	11,027
2006	1,005,297.39	101,274	64,489	940,808	24.28	38,748
2007	695,455.51	47,395	30,180	665,276	25.16	26,442
2008	929,263.07	32,004	20,380	908,883	26.07	34,863
2009	346,281.49	0	0	346,281	27.00	12,825
	28,678,531.55	7,965,045	5,072,002	23,606,530		1,224,947

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 19.3 4.27

FORTISBC ENERGY INC.

ACCOUNT 467.20 - TRANS. PLANT - TELEMETRY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L1						
NET SALVAGE PERCENT.. 0						
1972	20,657.58	18,069	20,658			
1974	4,612.17	3,920	4,612			
1976	8,260.32	6,817	8,260			
1977	4,344.98	3,528	4,345			
1978	14,078.53	11,244	14,079			
1979	1,440.46	1,131	1,440			
1980	27,834.89	21,470	27,835			
1981	1,654.26	1,253	1,654			
1982	8,407.98	6,244	8,408			
1984	8,673.99	6,176	8,674			
1985	34,907.66	24,296	34,908			
1986	13,700.85	9,317	13,701			
1987	7,999.60	5,306	8,000			
1988	12,721.24	8,226	12,721			
1989	960.12	604	960			
1991	117,323.96	69,456	117,324			
1992	92,120.01	52,754	92,120			
1993	122,632.08	67,775	122,632			
1994	151,736.81	80,724	151,737			
1995	302,169.13	154,309	302,169			
1996	120,568.42	58,837	120,568			
1997	212,515.46	98,890	212,515			
1998	99,718.76	44,009	99,719			
1999	1,865,795.96	777,421	1,865,796			
2000	372,797.36	145,887	372,797			
2001	511,497.45	186,528	511,497			
2002	161,418.32	54,128	161,418			
2003	104,929.43	31,689	104,929			
2004	441,703.13	116,610	441,703			
2005	22,377.46	4,953	22,377			
2006	1,139,124.34	196,693	1,104,783	34,341	12.41	2,767
2007	105,467.10	12,585	70,687	34,780	13.21	2,633
2008	176,830.37	10,845	60,915	115,915	14.08	8,233
2009	89,533.82	0	0-	89,534	15.00	5,969
	6,380,514.00	2,291,694	6,105,941	274,573		19,602

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 14.0 0.31

FORTISBC ENERGY INC.

ACCOUNT 468.00 - TRANS. PLANT - COMMUNICATIONS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-R2.5						
NET SALVAGE PERCENT.. 0						
1992	5,318.92	4,743	5,319			
1993	12,206.04	10,650	12,206			
1994	12,077.12	10,276	12,077			
1995	25,012.13	20,656	25,012			
1996	3,807.61	3,033	3,785	23	2.44	9
1997	27,190.20	20,687	25,813	1,377	2.87	480
1998	11,227.62	8,084	10,087	1,141	3.36	340
1999	3,013.81	2,027	2,529	485	3.93	123
2000	2,407.88	1,495	1,865	543	4.55	119
2001	199,364.98	112,476	140,346	59,019	5.23	11,285
2002	44,258.99	22,277	27,797	16,462	5.96	2,762
	345,885.30	216,404	266,836	79,050		15,118

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 5.2 4.37

FORTISBC ENERGY INC.

ACCOUNT 472.00 - DIST. SYSTEMS - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 29-L0.5						
NET SALVAGE PERCENT.. 0						
1958	21,817.93	14,490	16,587	5,231	9.74	537
1961	21,710.46	13,970	15,992	5,718	10.34	553
1962	15,408.41	9,803	11,222	4,186	10.55	397
1965	559.36	343	393	166	11.20	15
1968	15,488.52	9,138	10,461	5,028	11.89	423
1969	1,834.27	1,067	1,221	613	12.13	51
1970	15,351.61	8,798	10,072	5,280	12.38	426
1971	1,411.99	797	912	500	12.63	40
1972	4,054.62	2,254	2,580	1,475	12.88	115
1973	13,979.73	7,646	8,753	5,227	13.14	398
1974	14,144.35	7,604	8,705	5,439	13.41	406
1975	6,738.60	3,560	4,075	2,664	13.68	195
1976	2,188.00	1,136	1,300	888	13.95	64
1978	15.33	8	9	6		
1979	4,718.56	2,309	2,643	2,076	14.81	140
1980	7,195.67	3,449	3,948	3,248	15.10	215
1981	76,431.46	35,817	41,002	35,429	15.41	2,299
1982	25,409.62	11,645	13,331	12,079	15.71	769
1983	44,073.93	19,712	22,565	21,509	16.03	1,342
1984	28,822.21	12,573	14,393	14,429	16.35	883
1985	15,784.38	6,711	7,682	8,102	16.67	486
1986	116,667.82	48,236	55,218	61,450	17.01	3,613
1987	151,582.38	60,894	69,709	81,873	17.35	4,719
1988	17,436.24	6,800	7,784	9,652	17.69	546
1989	27,683.03	10,462	11,976	15,707	18.04	871
1990	44,063.07	16,106	18,437	25,626	18.40	1,393
1991	317,228.18	111,905	128,104	189,124	18.77	10,076
1992	134,001.15	45,560	52,155	81,846	19.14	4,276
1993	157,861.12	51,550	59,012	98,849	19.53	5,061
1994	464,159.55	145,328	166,365	297,795	19.92	14,950
1995	945,658.26	282,723	323,648	622,010	20.33	30,596
1996	1,013,309.40	287,922	329,600	683,709	20.76	32,934
1997	753,025.51	202,278	231,559	521,467	21.21	24,586
1998	375,235.37	94,586	108,278	266,957	21.69	12,308
1999	431,401.96	101,306	115,970	315,432	22.19	14,215
2000	530,637.60	114,910	131,544	399,094	22.72	17,566
2001	592,107.88	116,787	133,692	458,416	23.28	19,691
2002	222,346.98	39,333	45,027	177,320	23.87	7,429
2003	291,882.50	45,291	51,847	240,036	24.50	9,797
2004	1,216,305.08	161,477	184,852	1,031,453	25.15	41,012
2005	2,254,346.30	245,656	281,216	1,973,130	25.84	76,360
2006	2,464,870.80	207,394	237,415	2,227,456	26.56	83,865
2007	948,982.93	54,975	62,933	886,050	27.32	32,432
2008	1,062,817.21	31,885	36,500	1,026,317	28.13	36,485
2009	326,729.95	0	0	326,730	29.00	11,267
	15,197,479.28	2,656,194	3,040,687	12,156,792		505,802

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 24.0   3.33

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 50-R1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1959	792,828.22	501,702	190,670	602,158	18.36	32,797
1960	56,784.45	35,377	13,445	43,339	18.85	2,299
1962	99,061.06	59,734	22,702	76,359	19.85	3,847
1963	135,795.64	80,500	30,594	105,202	20.36	5,167
1964	130,865.76	76,216	28,966	101,900	20.88	4,880
1965	111,615.47	63,844	24,264	87,351	21.40	4,082
1966	102,388.65	57,481	21,845	80,544	21.93	3,673
1967	106,652.97	58,723	22,318	84,335	22.47	3,753
1968	104,371.32	56,319	21,404	82,967	23.02	3,604
1969	136,263.12	72,029	27,374	108,889	23.57	4,620
1970	269,341.27	139,357	52,962	216,379	24.13	8,967
1971	267,283.48	135,299	51,420	215,863	24.69	8,743
1972	348,885.71	172,559	65,581	283,305	25.27	11,211
1973	477,948.53	230,849	87,733	390,216	25.85	15,095
1974	603,739.39	284,603	108,163	495,576	26.43	18,751
1975	559,004.49	256,918	97,641	461,363	27.02	17,075
1976	815,676.20	365,097	138,754	676,922	27.62	24,508
1977	737,321.56	321,030	122,007	615,315	28.23	21,796
1978	886,202.20	375,041	142,533	743,669	28.84	25,786
1979	961,459.13	394,967	150,106	811,353	29.46	27,541
1980	1,375,041.22	547,816	208,196	1,166,845	30.08	38,791
1981	2,060,391.00	794,899	302,099	1,758,292	30.71	57,255
1982	1,975,272.26	736,777	280,010	1,695,262	31.35	54,075
1983	2,486,173.50	895,520	340,340	2,145,834	31.99	67,078
1984	2,308,822.97	802,085	304,830	2,003,993	32.63	61,416
1985	3,889,988.82	1,300,812	494,370	3,395,619	33.28	102,032
1986	1,774,782.14	570,060	216,650	1,558,132	33.94	45,908
1987	3,951,986.60	1,217,212	462,598	3,489,389	34.60	100,849
1988	1,870,241.63	551,347	209,538	1,660,704	35.26	47,099
1989	2,920,735.62	821,895	312,359	2,608,377	35.93	72,596
1990	159,467,104.41	42,737,184	16,242,141	143,224,963	36.60	3,913,250
1991	21,428,157.59	5,451,323	2,071,759	19,356,399	37.28	519,217
1992	23,446,123.93	5,650,516	2,147,462	21,298,662	37.95	561,230
1993	28,028,156.85	6,373,603	2,422,269	25,605,888	38.63	662,850
1994	25,467,590.08	5,439,877	2,067,409	23,400,181	39.32	595,122
1995	25,549,933.64	5,109,987	1,942,036	23,607,898	40.00	590,197
1996	23,810,624.85	4,433,538	1,684,953	22,125,672	40.69	543,762
1997	21,002,553.67	3,616,640	1,374,494	19,628,060	41.39	474,222
1998	18,999,490.02	3,009,519	1,143,759	17,855,731	42.08	424,328
1999	16,768,533.19	2,421,376	920,237	15,848,296	42.78	370,460
2000	20,016,226.59	2,606,113	990,446	19,025,781	43.49	437,475
2001	15,236,354.66	1,770,464	672,860	14,563,495	44.19	329,565
2002	17,007,231.24	1,734,738	659,282	16,347,949	44.90	364,097
2003	17,702,836.97	1,550,769	589,365	17,113,472	45.62	375,131
2004	21,679,649.87	1,586,950	603,115	21,076,535	46.34	454,824

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1						
NET SALVAGE PERCENT.. 0						
2005	27,863,203.65	1,638,356	622,652	27,240,552	47.06	578,847
2006	29,411,986.44	1,300,010	494,065	28,917,921	47.79	605,104
2007	36,412,546.89	1,077,811	409,619	36,002,928	48.52	742,022
2008	36,574,963.91	541,309	205,723	36,369,241	49.26	738,312
2009	16,494,685.58	0	0	16,494,686	50.00	329,894
9999	194,189.84	33,664	12,794	181,396		4,438
	634,879,068.25	110,059,815	41,827,912	593,051,156		14,509,641

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 40.9   2.29

FORTISBC ENERGY INC.

ACCOUNT 473.01 - LILO DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1959	588,382.66	573,673	294,991	293,392	1.00	293,392
1960	86,779.49	84,610	43,508	43,271	1.00	43,271
1962	83,652.87	81,562	41,940	41,713	1.00	41,713
1963	114,463.46	111,602	57,387	57,076	1.00	57,076
1964	93,554.59	91,216	46,905	46,650	1.00	46,650
1965	79,714.21	77,721	39,965	39,749	1.00	39,749
1966	133,049.39	129,723	66,705	66,344	1.00	66,344
1967	148,116.84	144,414	74,260	73,857	1.00	73,857
1968	161,069.55	157,043	80,754	80,316	1.00	80,316
1969	90,903.04	88,630	45,575	45,328	1.00	45,328
1970	154,900.78	151,028	77,661	77,240	1.00	77,240
1971	169,008.37	160,558	82,561	86,447	2.00	43,224
1972	196,258.03	181,539	93,350	102,908	3.00	34,303
1973	309,641.29	278,677	143,300	166,341	4.00	41,585
1974	422,741.95	369,899	190,207	232,535	5.00	46,507
1975	420,527.20	357,448	183,805	236,722	6.00	39,454
1976	595,190.93	491,033	252,496	342,695	7.00	48,956
1977	562,702.52	450,162	231,480	331,223	8.00	41,403
1978	569,237.49	441,159	226,850	342,387	9.00	38,043
1979	489,786.08	367,340	188,891	300,895	10.00	30,090
1980	718,192.44	520,690	267,746	450,446	11.00	40,950
1981	1,000,644.21	700,451	360,182	640,462	12.00	53,372
1982	965,421.01	651,659	335,092	630,329	13.00	48,487
1983	1,065,814.16	692,779	356,237	709,577	14.00	50,684
1984	1,009,825.60	631,141	324,542	685,284	15.00	45,686
1985	1,675,080.82	1,005,048	516,810	1,158,271	16.00	72,392
1986	617,212.66	354,897	182,493	434,720	17.00	25,572
1987	1,410,523.03	775,788	398,921	1,011,602	18.00	56,200
1988	1,103,175.46	579,167	297,816	805,359	19.00	42,387
1989	1,289,755.69	644,878	331,605	958,151	20.00	47,908
1990	1,748,767.77	830,665	427,140	1,321,628	21.00	62,935
1991	2,312,537.76	1,040,642	535,113	1,777,425	22.00	80,792
1992	2,491,952.90	1,059,080	544,594	1,947,359	23.00	84,668
1993	2,534,460.24	1,013,784	521,302	2,013,158	24.00	83,882
1994	1,986,267.05	744,850	383,012	1,603,255	25.00	64,130
1995	2,378,172.37	832,360	428,011	1,950,161	26.00	75,006
1996	2,098,032.30	681,860	350,622	1,747,410	27.00	64,719
1997	1,942,019.01	582,606	299,584	1,642,435	28.00	58,658
1998	1,409,286.93	387,554	199,286	1,210,001	29.00	41,724
1999	1,306,148.60	326,537	167,910	1,138,239	30.00	37,941
2000	2,146,687.34	483,005	248,368	1,898,319	31.00	61,236
2001	1,377,291.88	275,458	141,644	1,235,648	32.00	38,614

FORTISBC ENERGY INC.

ACCOUNT 473.01 - LILO DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	926,897.33	162,207	83,409	843,488	33.00	25,560
2003	968,651.37	145,298	74,715	893,936	34.00	26,292
2004	1,209,222.31	151,153	77,725	1,131,497	35.00	32,328
2005	14,862.04	1,486	764	14,098	36.00	392
	43,176,583.02	20,064,080	10,317,234	32,859,349		2,551,016

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 12.9   5.91

FORTISBC ENERGY INC.

ACCOUNT 474.00 - DIST. SYSTEMS - METERS/REG. INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-R2.5						
NET SALVAGE PERCENT.. 0						
1968	101,120.35	96,524	4,121	96,999	1.00	96,999
1970	48,278.65	46,084	1,968	46,311	1.00	46,311
1971	17,274.96	16,490	704	16,571	1.00	16,571
1972	33,130.56	31,595	1,349	31,782	1.02	31,159
1973	40,114.74	37,762	1,612	38,503	1.29	29,847
1974	83,385.28	77,586	3,312	80,073	1.53	52,335
1975	4,452.69	4,098	175	4,278	1.75	2,445
1976	50,153.86	45,663	1,950	48,204	1.97	24,469
1977	110,755.00	99,729	4,258	106,497	2.19	48,629
1978	162,243.86	144,397	6,165	156,079	2.42	64,495
1979	86,149.60	75,773	3,235	82,915	2.65	31,289
1980	73,992.83	64,239	2,743	71,250	2.90	24,569
1981	165,844.98	142,099	6,067	159,778	3.15	50,723
1982	243,705.49	205,709	8,783	234,922	3.43	68,490
1983	24,726.37	20,534	877	23,849	3.73	6,394
1984	48,247.32	39,343	1,680	46,567	4.06	11,470
1985	46,842.30	37,431	1,598	45,244	4.42	10,236
1986	36,018.37	28,127	1,201	34,817	4.82	7,223
1987	31,120.04	23,680	1,011	30,109	5.26	5,724
1988	427,194.03	315,735	13,480	413,714	5.74	72,076
1989	221,182.28	158,347	6,761	214,421	6.25	34,307
1990	288,356.50	199,096	8,500	279,856	6.81	41,095
1991	12,375.20	8,213	351	12,024	7.40	1,625
1992	3,063.87	1,947	83	2,981	8.02	372
1993	2,528,117.60	1,530,649	65,350	2,462,768	8.68	283,729
1994	9,802,338.35	5,631,933	240,452	9,561,886	9.36	1,021,569
1995	14,028,210.59	7,607,078	324,780	13,703,431	10.07	1,360,817
1996	5,036,492.80	2,564,028	109,470	4,927,023	10.80	456,206
1997	8,309,458.02	3,946,993	168,514	8,140,944	11.55	704,844
1998	5,753,789.32	2,529,078	107,977	5,645,812	12.33	457,892
1999	7,591,976.46	3,060,933	130,685	7,461,291	13.13	568,263
2000	5,309,733.45	1,942,885	82,950	5,226,783	13.95	374,680
2001	5,981,818.60	1,963,113	83,814	5,898,005	14.78	399,053
2002	6,096,089.40	1,762,318	75,241	6,020,848	15.64	384,965
2003	5,483,901.82	1,368,508	58,428	5,425,474	16.51	328,617
2004	8,000,409.95	1,676,486	71,576	7,928,834	17.39	455,942
2005	9,127,645.89	1,539,286	65,719	9,061,927	18.29	495,458
2006	10,290,538.93	1,309,677	55,916	10,234,623	19.20	533,053
2007	10,932,358.42	929,250	39,674	10,892,684	20.13	541,117
2008	8,836,260.23	377,573	16,120	8,820,140	21.06	418,810
2009	8,017,968.90	0	0-	8,017,969	22.00	364,453
	133,486,837.86	41,659,989	1,778,650	131,708,188		9,928,321

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.3 7.44

FORTISBC ENERGY INC.

ACCOUNT 474.01 - LILO DIST. SYSTEMS - METERS/REG. INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 30-SQUARE						
NET SALVAGE PERCENT.. 0						
1981	255.88	239	226	30	2.00	15
1983	127.94	111	105	23	4.00	6
1984	4,804,573.00	4,003,795	3,786,213	1,018,360	5.00	203,672
1985	167,763.83	134,211	126,917	40,847	6.00	6,808
1986	191,962.63	147,172	139,174	52,789	7.00	7,541
1987	158,404.01	116,162	109,849	48,555	8.00	6,069
1988	220,063.46	154,044	145,673	74,390	9.00	8,266
1989	238,944.01	159,297	150,640	88,304	10.00	8,830
1990	266,836.62	168,996	159,812	107,025	11.00	9,730
1991	208,719.79	125,232	118,426	90,294	12.00	7,524
1992	530,398.43	300,561	284,227	246,171	13.00	18,936
1993	784,997.67	418,663	395,911	389,087	14.00	27,792
1994	720,015.67	360,008	340,444	379,572	15.00	25,305
1995	678,814.42	316,782	299,567	379,247	16.00	23,703
1996	943,588.82	408,885	386,665	556,924	17.00	32,760
1997	1,206,134.53	482,454	456,236	749,899	18.00	41,661
1998	971,280.47	356,139	336,785	634,495	19.00	33,394
1999	974,105.25	324,699	307,054	667,051	20.00	33,353
2000	928,064.14	278,419	263,289	664,775	21.00	31,656
2001	954,592.37	254,561	240,727	713,865	22.00	32,448
2002	495,575.03	115,633	109,349	386,226	23.00	16,792
2003	503,107.83	100,622	95,154	407,954	24.00	16,998
2004	112,723.51	18,788	17,767	94,957	25.00	3,798
2005	9,083.74	1,211	1,145	7,939	26.00	305
	16,070,133.05	8,746,684	8,271,355	7,798,778		597,362

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.1   3.72

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 64-R2						
NET SALVAGE PERCENT.. 0						
1959	2,920,334.13	1,767,269	2,125,198	795,136	25.27	31,466
1960	56,165.77	33,453	40,228	15,938	25.88	616
1961	84,654.51	49,615	59,664	24,991	26.49	943
1962	253,537.55	146,101	175,691	77,847	27.12	2,870
1963	461,776.73	261,555	314,528	147,249	27.75	5,306
1964	460,129.01	256,020	307,872	152,257	28.39	5,363
1965	363,791.56	198,721	238,968	124,824	29.04	4,298
1966	702,531.33	376,620	452,898	249,633	29.69	8,408
1967	401,453.59	211,012	253,749	147,705	30.36	4,865
1968	446,752.07	230,149	276,762	169,990	31.03	5,478
1969	1,193,083.19	601,946	723,860	469,223	31.71	14,797
1970	1,436,224.07	709,136	852,759	583,465	32.40	18,008
1971	666,920.02	322,102	387,338	279,582	33.09	8,449
1972	996,164.86	470,220	565,455	430,710	33.79	12,747
1973	987,382.08	455,124	547,301	440,081	34.50	12,756
1974	1,290,576.31	580,359	697,901	592,675	35.22	16,828
1975	870,180.67	381,522	458,793	411,388	35.94	11,447
1976	1,344,350.57	574,078	690,347	654,004	36.67	17,835
1977	1,184,279.78	492,033	591,686	592,594	37.41	15,841
1978	1,467,813.72	592,865	712,939	754,875	38.15	19,787
1979	2,479,805.26	972,555	1,169,529	1,310,276	38.90	33,683
1980	3,100,429.46	1,179,124	1,417,935	1,682,494	39.66	42,423
1981	2,694,256.02	992,672	1,193,720	1,500,536	40.42	37,124
1982	4,915,129.92	1,751,801	2,106,598	2,808,532	41.19	68,185
1983	7,750,531.05	2,667,888	3,208,222	4,542,309	41.97	108,228
1984	3,631,131.08	1,205,644	1,449,826	2,181,305	42.75	51,025
1985	2,506,055.22	801,161	963,422	1,542,633	43.54	35,430
1986	2,752,185.62	845,857	1,017,171	1,735,015	44.33	39,139
1987	3,789,538.97	1,117,308	1,343,599	2,445,940	45.13	54,198
1988	2,580,693.42	728,633	876,205	1,704,488	45.93	37,111
1989	2,363,548.19	637,425	766,524	1,597,024	46.74	34,168
1990	317,592,506.13	81,583,163	98,106,405	219,486,101	47.56	4,614,931
1991	24,372,311.47	5,948,306	7,153,031	17,219,280	48.38	355,917
1992	22,228,597.55	5,136,807	6,177,177	16,051,421	49.21	326,182
1993	23,013,329.19	5,019,667	6,036,313	16,977,016	50.04	339,269
1994	25,969,625.41	5,323,773	6,402,010	19,567,615	50.88	384,584
1995	30,450,644.84	5,842,870	7,026,241	23,424,404	51.72	452,908
1996	28,147,959.96	5,026,944	6,045,064	22,102,896	52.57	420,447
1997	26,400,351.67	4,364,242	5,248,143	21,152,209	53.42	395,960
1998	26,058,155.67	3,957,713	4,759,279	21,298,877	54.28	392,389
1999	26,190,050.12	3,625,751	4,360,083	21,829,967	55.14	395,901
2000	19,432,653.09	2,429,082	2,921,050	16,511,603	56.00	294,850
2001	22,140,689.08	2,463,152	2,962,020	19,178,669	56.88	337,178
2002	22,053,704.64	2,153,765	2,589,973	19,463,732	57.75	337,034
2003	21,999,366.34	1,845,967	2,219,835	19,779,531	58.63	337,362

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 64-R2						
NET SALVAGE PERCENT.. 0						
2004	21,840,250.00	1,528,818	1,838,453	20,001,797	59.52	336,052
2005	22,773,031.56	1,280,983	1,540,424	21,232,608	60.40	351,533
2006	28,736,970.85	1,212,413	1,457,966	27,279,005	61.30	445,008
2007	26,842,910.18	759,117	912,863	25,930,047	62.19	416,949
2008	30,246,356.26	425,264	511,394	29,734,962	63.10	471,236
2009	20,012,234.10	0	0	20,012,234	64.00	312,691
	842,653,103.84	161,537,765	194,254,412	648,398,692		12,477,203

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 52.0   1.48

FORTISBC ENERGY INC.

ACCOUNT 475.01 - LILO DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1959	1,234,188.26	1,203,334	978,898	255,290	1.00	255,290
1960	38,244.10	37,288	30,333	7,911	1.00	7,911
1961	12,904.77	12,582	10,235	2,670	1.00	2,670
1962	44,831.15	43,710	35,558	9,273	1.00	9,273
1963	183,862.68	179,266	145,831	38,032	1.00	38,032
1964	106,139.88	103,486	84,185	21,955	1.00	21,955
1965	75,247.83	73,367	59,683	15,565	1.00	15,565
1966	267,660.47	260,969	212,295	55,365	1.00	55,365
1967	159,632.24	155,641	126,612	33,020	1.00	33,020
1968	374,618.83	365,253	297,129	77,490	1.00	77,490
1969	223,032.90	217,457	176,899	46,134	1.00	46,134
1970	350,255.91	341,500	277,806	72,450	1.00	72,450
1971	260,864.94	247,822	201,600	59,265	2.00	29,632
1972	268,830.46	248,668	202,289	66,541	3.00	22,180
1973	564,514.28	508,063	413,303	151,211	4.00	37,803
1974	681,235.90	596,081	484,905	196,331	5.00	39,266
1975	413,091.84	351,128	285,639	127,453	6.00	21,242
1976	582,180.96	480,299	390,718	191,463	7.00	27,352
1977	623,016.21	498,413	405,453	217,563	8.00	27,195
1978	338,786.03	262,559	213,589	125,197	9.00	13,911
1979	333,435.25	250,076	203,434	130,001	10.00	13,000
1980	542,411.60	393,248	319,903	222,509	11.00	20,228
1981	857,838.23	600,487	488,489	369,349	12.00	30,779
1982	1,298,106.84	876,222	712,796	585,311	13.00	45,024
1983	1,662,677.04	1,080,740	879,169	783,508	14.00	55,965
1984	849,181.09	530,738	431,749	417,432	15.00	27,829
1985	833,941.07	500,365	407,041	426,900	16.00	26,681
1986	232,851.37	133,890	108,918	123,933	17.00	7,290
1987	700,081.42	385,045	313,230	386,851	18.00	21,492
1988	420,271.05	220,642	179,490	240,781	19.00	12,673
1989	463,938.65	231,969	188,704	275,235	20.00	13,762
1990	1,398,613.88	664,342	540,434	858,180	21.00	40,866
1991	1,810,468.54	814,711	662,758	1,147,711	22.00	52,169
1992	1,373,176.11	583,600	474,752	898,424	23.00	39,062
1993	1,819,098.84	727,640	591,927	1,227,172	24.00	51,132
1994	2,333,339.70	875,002	711,804	1,621,536	25.00	64,861
1995	3,324,567.65	1,163,599	946,574	2,377,994	26.00	91,461
1996	2,093,849.09	680,501	553,580	1,540,269	27.00	57,047
1997	1,576,924.45	473,077	384,843	1,192,081	28.00	42,574
1998	1,037,163.62	285,220	232,023	805,141	29.00	27,763
1999	1,376,827.42	344,207	280,008	1,096,819	30.00	36,561
2000	1,361,659.46	306,373	249,231	1,112,428	31.00	35,885
2001	2,446,687.69	489,338	398,071	2,048,617	32.00	64,019

FORTISBC ENERGY INC.

ACCOUNT 475.01 - LILO DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	1,403,248.76	245,569	199,767	1,203,482	33.00	36,469
2003	678,581.03	101,787	82,803	595,778	34.00	17,523
2004	725,364.61	90,671	73,759	651,606	35.00	18,617
2005	7,644.22	764	622	7,022	36.00	195
	39,765,088.32	19,236,709	15,648,839	24,116,249		1,804,663

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.4   4.54

FORTISBC ENERGY INC.

ACCOUNT 476.00 - DIST. SYSTEMS - NGV FUEL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-R0.5						
NET SALVAGE PERCENT.. 0						
1996	63,432.30	54,370	39,833	23,599	1.00	23,599
1997	56,248.13	48,213	35,322	20,926	1.00	20,926
1998	50,153.69	40,696	29,815	20,339	1.32	15,408
1999	50,208.17	37,943	27,798	22,410	1.71	13,105
2000	266,663.32	185,902	136,197	130,466	2.12	61,541
2001	40,654.46	25,787	18,892	21,762	2.56	8,501
2002	43,497.59	24,731	18,118	25,379	3.02	8,404
	570,857.66	417,642	305,975	264,882		151,484

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 1.7   26.54

FORTISBC ENERGY INC.

ACCOUNT 477.10 - DIST. SYSTEMS - MEAS. & REG. ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 26-R2						
NET SALVAGE PERCENT.. 0						
1958	40,513.10	38,955	23,074	17,439	1.00	17,439
1963	1,338.85	1,287	762	577	1.00	577
1964	214.27	206	122	92	1.00	92
1965	784.71	751	445	340	1.13	301
1966	540.28	511	303	237	1.41	168
1969	10,292.23	9,394	5,564	4,728	2.27	2,083
1970	9,362.70	8,441	5,000	4,363	2.56	1,704
1971	5,754.34	5,124	3,035	2,719	2.85	954
1973	86,591.83	75,135	44,504	42,088	3.44	12,235
1974	11,176.62	9,565	5,666	5,511	3.75	1,470
1975	3,319.64	2,801	1,659	1,661	4.06	409
1976	33,116.74	27,525	16,304	16,813	4.39	3,830
1977	8,923.91	7,300	4,324	4,600	4.73	973
1978	4,340.83	3,491	2,068	2,273	5.09	447
1979	72,002.42	56,855	33,676	38,326	5.47	7,007
1980	78,936.45	61,115	36,200	42,736	5.87	7,280
1981	15,662.48	11,873	7,033	8,629	6.29	1,372
1982	187,372.91	138,871	82,256	105,117	6.73	15,619
1983	236,283.08	170,941	101,252	135,031	7.19	18,780
1984	165,691.64	116,750	69,154	96,538	7.68	12,570
1985	102,113.15	69,948	41,432	60,681	8.19	7,409
1986	624,955.84	415,358	246,025	378,931	8.72	43,455
1987	480,661.59	309,104	183,089	297,573	9.28	32,066
1988	7,410,552.88	4,600,249	2,724,825	4,685,728	9.86	475,226
1989	470,639.90	281,480	166,727	303,913	10.45	29,083
1990	139,394.13	80,044	47,412	91,982	11.07	8,309
1991	1,005,265.78	552,514	327,266	678,000	11.71	57,899
1992	1,133,738.45	594,340	352,040	781,698	12.37	63,193
1993	1,708,548.01	850,994	504,062	1,204,486	13.05	92,298
1994	2,478,615.76	1,167,800	691,713	1,786,903	13.75	129,957
1995	4,505,960.99	1,998,213	1,183,584	3,322,377	14.47	229,604
1996	2,985,982.60	1,240,317	734,666	2,251,317	15.20	148,113
1997	3,071,490.31	1,187,254	703,236	2,368,254	15.95	148,480
1998	2,152,858.89	769,238	455,636	1,697,223	16.71	101,569
1999	1,964,971.38	643,155	380,954	1,584,017	17.49	90,567
2000	3,548,939.53	1,053,751	624,159	2,924,781	18.28	159,999
2001	4,570,215.96	1,214,626	719,449	3,850,767	19.09	201,716
2002	3,227,007.74	755,862	447,713	2,779,295	19.91	139,593
2003	7,948,954.25	1,605,053	950,706	6,998,248	20.75	337,265
2004	3,771,650.50	639,747	378,936	3,392,714	21.59	157,143
2005	4,848,286.33	661,985	392,108	4,456,178	22.45	198,493
2006	7,842,211.07	808,375	478,817	7,363,394	23.32	315,754
2007	5,273,046.31	363,049	215,041	5,058,005	24.21	208,922
2008	3,491,281.16	120,868	71,593	3,419,688	25.10	136,243
2009	2,162,673.00	0	0-	2,162,673	26.00	83,180
	77,892,234.54	22,730,215	13,463,590	64,428,645		3,700,846

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 17.4   4.75

FORTISBC ENERGY INC.

ACCOUNT 477.20 - DIST. SYSTEMS - TELEMETRY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-R1.5						
NET SALVAGE PERCENT.. 0						
1959	202.89	192	203			
1969	9,476.34	8,083	9,476			
1971	140.82	117	141			
1973	2,713.40	2,193	2,713			
1976	195.90	151	196			
1979	14,378.32	10,459	14,378			
1982	17,668.21	11,988	17,668			
1983	49,062.59	32,418	49,063			
1984	2,366.11	1,520	2,366			
1985	37,831.32	23,567	37,831			
1986	71,707.63	43,263	71,708			
1987	606.69	353	607			
1988	54,885.79	30,817	54,886			
1989	8,939.14	4,824	8,939			
1990	15,477.34	8,002	15,477			
1991	47,391.77	23,397	47,392			
1992	94,980.29	44,641	94,980			
1993	111,080.65	49,493	111,081			
1994	226,107.90	95,133	226,108			
1995	283,361.85	112,087	283,362			
1996	1,480,236.77	547,140	1,480,237			
1997	560,475.29	192,428	560,475			
1998	319,011.07	101,021	319,011			
1999	279,364.29	80,912	279,364			
2000	307,641.01	80,670	307,641			
2001	364,265.96	85,399	364,266			
2002	259,286.17	53,491	259,286			
2003	454,519.38	80,804	454,519			
2004	124,715.95	18,569	124,716			
2005	38,735.40	4,634	38,735			
2006	189,560.91	17,131	189,561			
2007	47,814.20	2,887	47,814			
2008	194,821.53	5,917	194,822			
2009	72,588.09	0	637,897	565,308-	27.00	20,937-
	5,741,610.97	1,773,701	6,306,919	565,308-		20,937-

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 27.0 -0.36

FORTISBC ENERGY INC.

ACCOUNT 477.30 - DIST. SYSTEMS - MEAS. & REG. EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2.5						
NET SALVAGE PERCENT.. 0						
1989	50,316.16	43,876	50,316			
1991	253.68	212	254			
1995	12,447.44	9,070	12,447			
1999	5,185.29	2,925	5,185			
2000	1,661.74	857	1,662			
2001	44,063.55	20,504	44,064			
2003	49,223.00	17,655	86,258	37,035-	9.62	3,850-
	163,150.86	95,099	200,186	37,036-		3,850-

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 9.6 -2.36

FORTISBC ENERGY INC.

ACCOUNT 478.10 - DIST. SYSTEMS - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
1960	215.79	205	104	112	1.00	112
1964	50.00	48	24	26	1.00	26
1979	7.48	7	7			
1988	17,830,798.67	13,961,515	7,114,830	10,715,969	4.34	2,469,117
1989	5,684,558.52	4,325,949	2,204,517	3,480,042	4.78	728,042
1990	12,279,379.32	9,049,903	4,611,858	7,667,521	5.26	1,457,704
1991	3,131,992.13	2,226,846	1,134,807	1,997,185	5.78	345,534
1992	3,835,512.00	2,617,737	1,334,007	2,501,505	6.35	393,938
1993	3,856,317.87	2,516,247	1,282,287	2,574,031	6.95	370,364
1994	5,061,208.96	3,140,480	1,600,398	3,460,811	7.59	455,970
1995	8,082,449.32	4,744,398	2,417,760	5,664,689	8.26	685,798
1996	9,254,804.05	5,108,652	2,603,385	6,651,419	8.96	742,346
1997	7,580,404.05	3,911,488	1,993,306	5,587,098	9.68	577,180
1998	7,446,335.23	3,563,071	1,815,752	5,630,583	10.43	539,845
1999	9,687,070.37	4,257,467	2,169,618	7,517,452	11.21	670,602
2000	7,935,330.78	3,170,165	1,615,526	6,319,805	12.01	526,212
2001	5,670,945.60	2,033,034	1,036,040	4,634,906	12.83	361,255
2002	11,364,705.32	3,596,929	1,833,006	9,531,699	13.67	697,271
2003	16,139,000.58	4,414,017	2,249,396	13,889,605	14.53	955,926
2004	12,954,467.15	2,973,050	1,515,075	11,439,392	15.41	742,336
2005	8,335,771.61	1,542,118	785,868	7,549,904	16.30	463,184
2006	7,220,564.15	1,007,269	513,307	6,707,257	17.21	389,730
2007	8,896,706.43	831,842	423,910	8,472,796	18.13	467,336
2008	7,178,515.18	337,390	171,935	7,006,580	19.06	367,607
2009	8,449,942.01	0	0-	8,449,942	20.00	422,497
	187,877,052.57	79,329,827	40,426,723	147,450,330		14,829,932

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 9.9   7.89

FORTISBC ENERGY INC.

ACCOUNT 478.11 - LILO DIST. SYSTEMS - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1981	126.00	121	96	30	1.00	30
1983	150.97	145	115	36	1.00	36
1985	60,995.50	58,556	46,512	14,484	1.00	14,484
1986	61,657.50	56,725	45,057	16,600	2.00	8,300
1987	67,834.10	59,694	47,416	20,418	3.00	6,806
1988	70,040.80	58,834	46,733	23,308	4.00	5,827
1989	312,479.50	249,984	198,565	113,914	5.00	22,783
1990	253,358.90	192,553	152,947	100,412	6.00	16,735
1991	265,937.01	191,475	152,091	113,846	7.00	16,264
1992	667,505.94	453,904	360,542	306,964	8.00	38,370
1993	729,710.91	467,015	370,956	358,755	9.00	39,862
1994	755,885.15	453,531	360,245	395,640	10.00	39,564
1995	979,268.76	548,391	435,594	543,675	11.00	49,425
1996	855,740.65	444,985	353,457	502,284	12.00	41,857
1997	938,391.26	450,428	357,781	580,610	13.00	44,662
1998	856,857.81	377,017	299,470	557,388	14.00	39,813
1999	926,264.48	370,506	294,298	631,966	15.00	42,131
2000	775,545.79	279,196	221,769	553,777	16.00	34,611
2001	656,627.74	210,121	166,901	489,727	17.00	28,807
2002	259,093.19	72,546	57,624	201,469	18.00	11,193
2003	453,293.58	108,790	86,414	366,880	19.00	19,309
2004	73,662.72	14,733	11,702	61,961	20.00	3,098
2005	6,297.02	1,008	801	5,496	21.00	262
	10,026,725.28	5,120,258	4,067,086	5,959,639		524,229

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 11.4 5.23

FORTISBC ENERGY INC.

ACCOUNT 478.20 - DIST. SYSTEMS - INSTRUMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R5						
NET SALVAGE PERCENT.. 0						
1983	361,761.94	263,569	214,918	146,844	9.50	15,457
1984	2,933.10	2,063	1,682	1,251	10.38	121
1985	5,631.05	3,818	3,113	2,518	11.27	223
1986	23,355.78	15,221	12,411	10,945	12.19	898
1987	96,807.57	60,491	49,325	47,483	13.13	3,616
1988	115,160.76	68,833	56,127	59,034	14.08	4,193
1989	93,986.33	53,572	43,683	50,303	15.05	3,342
1990	165,438.23	89,668	73,117	92,321	16.03	5,759
1991	344,502.95	177,075	144,390	200,113	17.01	11,764
1992	754,659.62	366,334	298,714	455,946	18.01	25,316
1993	835,661.00	382,014	311,500	524,161	19.00	27,587
1994	901,190.00	386,223	314,932	586,258	20.00	29,313
1995	785,627.00	314,251	256,245	529,382	21.00	25,209
1996	655,670.92	243,536	198,583	457,088	22.00	20,777
1997	407,431.51	139,692	113,907	293,525	23.00	12,762
1998	53,827.57	16,917	13,794	40,034	24.00	1,668
1999	354,932.07	101,408	82,690	272,242	25.00	10,890
2000	253,791.63	65,260	53,214	200,578	26.00	7,715
2001	375,867.06	85,912	70,054	305,813	27.00	11,326
2002	356,603.79	71,321	58,156	298,448	28.00	10,659
2003	1,390,662.14	238,401	194,396	1,196,266	29.00	41,251
2004	1,363,377.05	194,772	158,820	1,204,557	30.00	40,152
2005	288,290.84	32,949	26,867	261,424	31.00	8,433
2006	508,057.41	43,546	35,508	472,549	32.00	14,767
2007	447,712.81	25,582	20,860	426,853	33.00	12,935
2008	308,436.81	8,812	7,185	301,252	34.00	8,860
2009	53,796.50	0	0	53,796	35.00	1,537
	11,305,173.44	3,451,240	2,814,191	8,490,982		356,530

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 23.8 3.15

FORTISBC ENERGY INC.

ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL

SURVIVOR CURVE.. IOWA 20-L0.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1988	793,936.00	392,204	424,108	369,828	10.12	36,544
1991	170,588.40	76,509	82,733	87,855	11.03	7,965
1992	84,431.17	36,516	39,486	44,945	11.35	3,960
1993	3,408.08	1,418	1,533	1,875	11.68	161
1994	616,140.47	245,840	265,838	350,302	12.02	29,143
1995	6,726.89	2,566	2,775	3,952	12.37	319
1996	893,099.53	324,642	351,050	542,050	12.73	42,581
1997	114,527.82	39,512	42,726	71,802	13.10	5,481
1998	414,934.71	135,269	146,273	268,662	13.48	19,930
1999	139,534.49	42,698	46,171	93,363	13.88	6,726
2000	199,307.15	56,803	61,424	137,883	14.30	9,642
2001	897,617.37	235,176	254,307	643,310	14.76	43,585
2002	215,114.19	51,090	55,246	159,868	15.25	10,483
2003	206,424.47	43,556	47,099	159,325	15.78	10,097
2004	93,557.75	17,028	18,413	75,145	16.36	4,593
2005	240,438.48	36,306	39,260	201,178	16.98	11,848
2006	169,411.09	19,906	21,525	147,886	17.65	8,379
2007	117,531.97	9,579	10,358	107,174	18.37	5,834
2008	104,998.31	4,515	4,882	100,116	19.14	5,231
2009	953,531.14	0	0	953,531	20.00	47,677
	6,435,259.48	1,771,133	1,915,207	4,520,052		310,179

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 14.6 4.82

FORTISBC ENERGY INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
1960	85,734.03	61,576	59,894	25,840	12.68	2,038
1967	70,596.50	45,605	44,360	26,236	15.93	1,647
1970	13,832.70	8,456	8,225	5,608	17.49	321
1974	688.62	387	376	313	19.74	16
1975	181.34	99	96	85	20.33	4
1976	248,769.72	133,119	129,484	119,286	20.92	5,702
1977	8,927.00	4,656	4,529	4,398	21.53	204
1978	20,357.44	10,337	10,055	10,302	22.15	465
1979	305,827.48	151,011	146,887	158,940	22.78	6,977
1980	4,921.37	2,360	2,296	2,625	23.42	112
1981	8,968.67	4,171	4,057	4,912	24.07	204
1982	7,755.47	3,495	3,400	4,355	24.72	176
1983	11,041.06	4,811	4,680	6,361	25.39	251
1984	45,537.81	19,166	18,643	26,895	26.06	1,032
1985	1,086.55	441	429	658	26.74	25
1986	246.00	96	93	153	27.43	6
1987	3,350.06	1,256	1,222	2,128	28.13	76
1988	527,194.04	189,437	184,263	342,931	28.83	11,895
1989	452,674.55	155,417	151,173	301,502	29.55	10,203
1990	114,839.26	37,617	36,590	78,249	30.26	2,586
1991	27,623.86	8,600	8,365	19,259	30.99	621
1992	3,313,005.15	977,701	951,000	2,362,005	31.72	74,464
1993	141,792.70	39,513	38,434	103,359	32.46	3,184
1994	3,763,964.63	986,987	960,032	2,803,933	33.20	84,456
1995	4,263,857.08	1,047,033	1,018,438	3,245,419	33.95	95,594
1996	4,365,619.35	998,286	971,022	3,394,597	34.71	97,799
1997	446,730.18	94,609	92,025	354,705	35.47	10,000
1998	1,376,344.34	268,236	260,910	1,115,434	36.23	30,788
1999	227,140.28	40,381	39,278	187,862	37.00	5,077
2000	650,787.40	104,412	101,560	549,227	37.78	14,538
2001	1,244,864.63	178,153	173,288	1,071,577	38.56	27,790
2002	516,034.79	64,793	63,023	453,012	39.35	11,512
2003	1,490,878.55	161,015	156,618	1,334,261	40.14	33,240
2004	1,031,744.21	93,084	90,542	941,202	40.94	22,990
2005	51,621,020.38	3,739,427	3,637,302	47,983,718	41.74	1,149,586
2006	1,072,711.46	58,398	56,803	1,015,908	42.55	23,876
2007	3,161,746.55	115,214	112,068	3,049,679	43.36	70,334
2008	901,417.60	16,424	15,975	885,443	44.18	20,042
2009	1,012,764.53	0	0	1,012,764	45.00	22,506
	82,562,577.34	9,825,779	9,557,435	73,005,142		1,842,337

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 39.6 2.23

FORTISBC ENERGY INC.

ACCOUNT 482.30 - GENERAL PLANT - STRUCTURES (LEASED)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R0.5						
NET SALVAGE PERCENT.. 0						
2003	86,694.25	15,865	86,694			
2004	1,189.47	182	1,189			
2007	464.16	29	464			
2008	14,795.00	459	14,795			
2009	24,189.31	0	269,567	245,378-	20.00	12,269-
	127,332.19	16,535	372,709	245,377-		12,269-

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 20.0   -9.64

FORTISBC ENERGY INC.

ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 5-L0.5						
NET SALVAGE PERCENT.. 20						
1996	63,201.72	39,539	50,561			
1997	56,043.66	34,164	44,835			
1998	49,971.37	29,423	39,977			
1999	24,454.20	13,812	19,563			
2000	39,967.90	21,487	31,974			
2001	45,166.38	22,836	36,133			
2002	64,592.94	30,281	51,674			
2003	61,663.52	26,441	49,331			
2004	48,021.89	18,440	38,418			
2005	80,897.83	26,923	64,718			
2006	78,529.59	21,737	56,955	5,869	3.27	1,795
2007	16,704.34	3,501	9,173	4,190	3.69	1,136
2008	147,821.68	17,739	46,479	71,778	4.25	16,889
2009	186,892.26	0	0	149,514	5.00	29,903
	963,929.28	306,323	539,791	231,352		49,723

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 4.7 5.16

FORTISBC ENERGY INC.

ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-L0.5						
NET SALVAGE PERCENT.. 15						
1996	20,529.03	9,807	9,018	8,432	4.38	1,925
1997	24,640.44	11,226	10,322	10,622	4.64	2,289
1998	16,231.58	7,009	6,445	7,352	4.92	1,494
1999	16,249.22	6,616	6,083	7,729	5.21	1,483
2000	12,982.28	4,944	4,546	6,489	5.52	1,176
2001	16,506.95	5,837	5,367	8,664	5.84	1,484
2002	23,621.28	7,650	7,034	13,044	6.19	2,107
2005	31,797.50	7,081	6,511	20,517	7.38	2,780
2006	26,606.29	4,772	4,388	18,227	7.89	2,310
2008	22,857.30	1,593	1,465	17,964	9.18	1,957
	212,021.87	66,535	61,179	119,039		19,005

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 6.3 8.96

FORTISBC ENERGY INC.

ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-R1.5						
NET SALVAGE PERCENT.. +10						
2001	29,463.87	19,623	10,950	15,567	1.82	8,553
2002	78,179.14	47,745	26,642	43,719	2.25	19,431
2003	45,936.55	25,042	13,974	27,369	2.76	9,916
2004	10,896.16	5,127	2,861	6,946	3.34	2,080
2005	148,469.18	57,649	32,168	101,454	3.98	25,491
2008	107,898.88	11,236	6,269	90,840	6.19	14,675
2009	79,777.93	0	0	71,800	7.00	10,257
	500,621.71	166,422	92,864	357,695		90,403

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 4.0 18.06

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 401.01 - FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	1,082.17	514	371	711	21.00	34
1991	186,139.77	83,763	60,447	125,693	22.00	5,713
1992	2,554.74	1,086	783	1,771	23.00	77
	189,776.68	85,363	61,601	128,175		5,824

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 22.0   3.07

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 402.03 - INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	694,036.53	312,316	456,444	237,593	22.00	10,800
2003	500,000.00	75,000	109,611	390,389	34.00	11,482
2009	25,000.00	0	0	25,000	40.00	625
	1,219,036.53	387,316	566,055	652,982		22,907

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 28.5 1.88

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 462.00 - TRANS. PLANT - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. 0						
1991	1,839,678.93	1,060,262	930,732	908,947	12.71	71,514
1992	70,386.00	38,548	33,839	36,547	13.57	2,693
1993	6,445.00	3,339	2,931	3,514	14.46	243
1994	25,252.00	12,323	10,818	14,434	15.36	940
1997	67,885.45	26,792	23,519	44,366	18.16	2,443
1998	3,248,059.83	1,177,974	1,034,063	2,213,997	19.12	115,795
1999	2,525,508.06	834,251	732,332	1,793,176	20.09	89,257
2000	918,083.31	273,589	240,165	677,918	21.06	32,190
2001	173.60	46	40	134	22.04	6
2002	805,800.84	187,212	164,341	641,460	23.03	27,853
2003	11,096.50	2,212	1,942	9,154	24.02	381
2004	28,186.18	4,688	4,115	24,071	25.01	962
2006	25,455.91	2,546	2,235	23,221	27.00	860
2007	1,611,352.07	107,429	94,304	1,517,048	28.00	54,180
2008	81,784.55	2,726	2,393	79,392	29.00	2,738
2009	281,334.13	0	0	281,334	30.00	9,378
	11,546,482.36	3,733,937	3,277,769	8,268,713		411,433

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 20.1 3.56

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 463.00 – TRANS. PLANT – MEAS. & REG. STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-S1						
NET SALVAGE PERCENT.. 0						
1991	3,461,744.73	1,667,419	1,978,586	1,483,159	15.55	95,380
1996	5,526.35	2,072	2,459	3,067	18.75	164
1997	78,158.95	27,460	32,584	45,575	19.46	2,342
1998	52,010.54	17,007	20,181	31,830	20.19	1,577
1999	526,828.00	158,928	188,586	338,242	20.95	16,145
2000	31,664.89	8,718	10,345	21,320	21.74	981
2002	36,518.20	8,034	9,533	26,985	23.40	1,153
2003	354.09	68	81	273	24.27	11
2006	1,692,325.67	166,982	198,144	1,494,182	27.04	55,258
2007	1,739,085.70	115,354	136,881	1,602,205	28.01	57,201
2008	81,460.86	2,715	3,221	78,240	29.00	2,698
	7,705,677.98	2,174,757	2,580,601	5,125,077		232,910

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 22.0 3.02

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 464.00 - TRANS. PLANT - OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
2004	33,804.63	4,704	4,796	29,009	30.13	963
2005	93,698.28	10,467	10,673	83,025	31.09	2,670
2006	1,991.80	167	170	1,822	32.06	57
2007	27.83	2	2	25	33.04	1
	129,522.54	15,340	15,641	113,881		3,691

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 30.9 2.85

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 465.00 - TRANS. PLANT - TRANS. PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. 0						
1991	302,604,769.85	80,447,478	79,179,618	223,425,152	47.72	4,682,002
1992	2,494,449.68	627,454	617,565	1,876,885	48.65	38,579
1993	439,615.00	104,290	102,646	336,969	49.58	6,796
1994	315,663.00	70,320	69,212	246,451	50.52	4,878
1995	113,197.00	23,580	23,208	89,989	51.46	1,749
1996	294,612.96	57,111	56,211	238,402	52.40	4,550
1997	275,629.41	49,401	48,622	227,007	53.35	4,255
1999	209,509.18	31,395	30,900	178,609	55.26	3,232
2000	713,580.65	96,390	94,871	618,710	56.22	11,005
2001	1,196,533.66	143,764	141,498	1,055,036	57.19	18,448
2002	2,652,317.33	279,103	274,705	2,377,612	58.16	40,881
2003	777,301.14	70,198	69,092	708,209	59.13	11,977
2004	645,083.76	48,626	47,860	597,224	60.10	9,937
2005	2,120,753.10	128,221	126,200	1,994,553	61.07	32,660
2006	3,229,556.50	146,557	144,248	3,085,308	62.05	49,723
2007	3,770,698.98	114,290	112,489	3,658,210	63.03	58,039
2008	894,934.18	13,496	13,283	881,651	64.02	13,771
2009	850,459.97	0	0-	850,460	65.00	13,084
	323,598,665.35	82,451,674	81,152,228	242,446,438		5,005,566

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 48.4 1.55

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 465.11 – INTERMED. PIPE - WHISTLER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
2008	8,227.20	115	162	8,065	69.02	117
2009	41,585,446.87	0	0	41,585,447	70.00	594,078
	41,593,674.07	115	162	41,593,512		594,195

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 70.0 1.43

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 466.00 - TRANS. PLANT - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1991	17,533,509.37	8,310,883	7,984,888	9,548,621	18.41	518,665
1992	617,142.00	277,893	266,993	350,149	19.24	18,199
1993	335,259.00	142,820	137,218	198,041	20.09	9,858
1994	255,900.00	102,798	98,766	157,134	20.94	7,504
1995	147,313.00	55,516	53,338	93,975	21.81	4,309
1996	580,381.49	203,963	195,962	384,419	22.70	16,935
1997	1,180,372.98	384,802	369,708	810,665	23.59	34,365
1998	5,807,178.88	1,742,154	1,673,818	4,133,361	24.50	168,709
1999	6,871,039.32	1,882,665	1,808,817	5,062,222	25.41	199,222
2000	341,290.14	84,445	81,133	260,157	26.34	9,877
2001	157,418.52	34,767	33,403	124,016	27.27	4,548
2002	64,219.67	12,440	11,952	52,268	28.22	1,852
2003	4,508.76	751	722	3,787	29.17	130
2004	11,725.72	1,632	1,568	10,158	30.13	337
2005	1,622,315.40	181,229	174,120	1,448,195	31.09	46,581
2006	428,261.99	35,974	34,563	393,699	32.06	12,280
2007	18,356,843.23	1,027,983	987,660	17,369,183	33.04	525,702
2008	2,884,421.17	80,764	77,596	2,806,825	34.02	82,505
2009	3,475,678.07	0	0-	3,475,678	35.00	99,305
	60,674,778.71	14,563,479	13,992,225	46,682,554		1,760,883

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 26.5   2.90

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 467.10 - TRANS. PLANT - MEAS. & REG. EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-L1						
NET SALVAGE PERCENT.. 0						
1991	8,343,658.44	3,479,639	2,427,961	5,915,697	15.74	375,838
1992	77,407.00	31,192	21,765	55,642	16.12	3,452
1993	51,286.00	19,926	13,904	37,382	16.51	2,264
1994	74,109.00	27,695	19,325	54,784	16.91	3,240
1996	42,594.79	14,561	10,160	32,435	17.77	1,825
1997	156,070.63	50,636	35,332	120,739	18.24	6,619
1998	795,811.52	243,463	169,879	625,933	18.74	33,401
1999	1,595,372.90	456,165	318,294	1,277,079	19.28	66,239
2000	134,094.41	35,410	24,708	109,386	19.87	5,505
2001	7,834.35	1,886	1,316	6,518	20.50	318
2002	284,436.26	61,418	42,855	241,581	21.17	11,411
2003	225,517.40	42,765	29,840	195,677	21.88	8,943
2004	458,183.56	73,987	51,625	406,559	22.64	17,958
2005	273,822.14	36,103	25,191	248,631	23.44	10,607
2006	1,083,381.00	109,140	76,154	1,007,227	24.28	41,484
2007	342,570.66	23,346	16,290	326,281	25.16	12,968
2008	494,296.05	17,024	11,878	482,418	26.07	18,505
2009	48,237.23	0	0	48,237	27.00	1,787
	14,488,683.34	4,724,356	3,296,477	11,192,206		622,364

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 18.0 4.30

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 467.31 – INTERMED. PRESSURE - MEAS. & REG. EQUIPMENT WHISTLER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2.5						
NET SALVAGE PERCENT.. 0						
2009	311,834.26	0	0	311,834	25.00	12,473
	311,834.26	0	0	311,834		12,473

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 25.0 4.00

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 468.00 - TRANS. PLANT - COMMUNICATIONS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

SURVIVOR CURVE.. IOWA 12-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1991	1,958,059.29	1,468,544	1,161,255	796,804	3.00	265,601
1997	122,787.93	92,091	72,821	49,967	3.00	16,656
1998	116,792.80	84,091	66,495	50,298	3.36	14,970
1999	180,141.42	121,145	95,796	84,345	3.93	21,462
2000	37,020.67	22,984	18,175	18,846	4.55	4,142
2001	8,082.15	4,560	3,606	4,476	5.23	856
2002	165,788.13	83,446	65,985	99,803	5.96	16,745
2003	625,406.37	274,660	217,188	408,218	6.73	60,656
2004	4,920.95	1,833	1,449	3,472	7.53	461
2006	2,110.34	485	384	1,726	9.24	187
2007	256,906.96	39,821	31,488	225,419	10.14	22,231
2008	42,417.02	3,323	2,628	39,789	11.06	3,598
2009	167,124.29	0	0-	167,125	12.00	13,927
	3,687,558.32	2,196,983	1,737,270	1,950,289		441,492

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 4.4 11.97

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 472.00 - DIST. SYSTEMS - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 29-L0.5						
NET SALVAGE PERCENT.. 0						
1991	693,900.18	244,780	302,528	391,372	18.77	20,851
1992	603,382.93	205,150	253,549	349,834	19.14	18,278
1993	74,518.63	24,334	30,075	44,444	19.53	2,276
1994	306,478.00	95,958	118,596	187,882	19.92	9,432
1995	37,358.45	11,169	13,804	23,554	20.33	1,159
1997	180,409.99	48,462	59,895	120,515	21.21	5,682
1998	102,430.81	25,820	31,911	70,520	21.69	3,251
1999	21,650.99	5,084	6,284	15,367	22.19	693
2000	10,165.74	2,201	2,720	7,446	22.72	328
2003	36,812.64	5,712	7,060	29,753	24.50	1,214
2004	37,465.44	4,974	6,147	31,318	25.15	1,245
2005	16,980.96	1,850	2,287	14,694	25.84	569
2008	9,416.87	283	349	9,068	28.13	322
2009	48,455.56	0	0	48,455	29.00	1,671
	2,179,427.19	675,777	835,205	1,344,222		66,971

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 20.1 3.07

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 473.00 - DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1						
NET SALVAGE PERCENT.. 0						
1990	4,573,436.94	1,225,681	1,232,557	3,340,880	36.60	91,281
1991	2,791,750.30	710,221	714,205	2,077,545	37.28	55,728
1992	13,773,159.18	3,319,331	3,337,951	10,435,208	37.95	274,973
1993	12,773,223.50	2,904,631	2,920,925	9,852,298	38.63	255,043
1994	12,020,883.08	2,567,661	2,582,065	9,438,818	39.32	240,051
1995	10,795,693.31	2,159,139	2,171,251	8,624,442	40.00	215,611
1996	11,108,085.75	2,068,326	2,079,929	9,028,157	40.69	221,877
1997	11,329,060.22	1,950,864	1,961,808	9,367,252	41.39	226,317
1998	8,938,166.51	1,415,806	1,423,748	7,514,419	42.08	178,575
1999	7,786,775.84	1,124,410	1,130,718	6,656,058	42.78	155,588
2000	6,902,443.91	898,698	903,739	5,998,705	43.49	137,933
2001	5,182,239.80	602,176	605,554	4,576,686	44.19	103,568
2002	6,253,679.72	637,875	641,453	5,612,227	44.90	124,994
2003	6,244,332.17	547,003	550,072	5,694,260	45.62	124,819
2004	6,501,677.79	475,923	478,593	6,023,085	46.34	129,976
2005	6,891,870.06	405,242	407,515	6,484,355	47.06	137,789
2006	6,818,188.13	301,364	303,055	6,515,133	47.79	136,328
2007	7,497,637.83	221,930	223,175	7,274,463	48.52	149,927
2008	9,390,836.61	138,984	139,763	9,251,074	49.26	187,801
2009	6,271,959.75	0	0	6,271,959	50.00	125,439
	163,845,100.40	23,675,265	23,808,076	140,037,024		3,273,618

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 42.8 2.00

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 474.00 - DIST. SYSTEMS - METERS/REG. INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-R2.5						
NET SALVAGE PERCENT.. 0						
1990	444,415.61	306,847	206,511	237,905	6.81	34,935
1991	751,187.52	498,518	335,507	415,681	7.40	56,173
1992	1,574,688.00	1,000,635	673,437	901,251	8.02	112,375
1993	1,525,841.74	923,821	621,740	904,102	8.68	104,159
1994	1,521,656.27	874,268	588,391	933,265	9.36	99,708
1995	1,277,332.35	692,659	466,166	811,166	10.07	80,553
1996	1,202,319.66	612,089	411,942	790,378	10.80	73,183
1997	1,307,197.50	620,919	417,885	889,312	11.55	76,997
1998	1,124,959.71	494,476	332,787	792,173	12.33	64,248
1999	968,165.55	390,345	262,706	705,460	13.13	53,729
2000	780,692.15	285,663	192,254	588,438	13.95	42,182
2001	443,981.75	145,706	98,062	345,920	14.78	23,405
2002	553,059.91	159,884	107,603	445,457	15.64	28,482
2003	946,308.97	236,151	158,932	787,377	16.51	47,691
2004	955,138.64	200,149	134,702	820,437	17.39	47,179
2005	1,156,446.09	195,023	131,252	1,025,194	18.29	56,052
2006	861,259.64	109,613	73,771	787,489	19.20	41,015
2007	1,114,605.61	94,741	63,762	1,050,844	20.13	52,203
2008	1,269,887.26	54,262	36,519	1,233,368	21.06	58,564
2009	1,162,154.78	0	0-	1,162,155	22.00	52,825
	20,941,298.71	7,895,769	5,313,929	15,627,370		1,205,658

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.0   5.76

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 475.00 - DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 64-R2						
NET SALVAGE PERCENT.. 0						
1990	14,046,806.73	3,608,344	4,357,030	9,689,777	47.56	203,738
1991	27,204,514.48	6,639,534	8,017,154	19,187,360	48.38	396,597
1992	55,216,934.30	12,760,081	15,407,638	39,809,296	49.21	808,968
1993	19,021,712.09	4,149,016	5,009,885	14,011,827	50.04	280,013
1994	20,893,834.93	4,283,236	5,171,954	15,721,881	50.88	308,999
1995	16,549,956.51	3,175,606	3,834,504	12,715,453	51.72	245,852
1996	13,544,863.41	2,418,977	2,920,884	10,623,979	52.57	202,092
1997	15,586,315.96	2,576,574	3,111,181	12,475,135	53.42	233,529
1998	12,072,298.66	1,833,541	2,213,978	9,858,321	54.28	181,620
1999	12,459,822.92	1,724,938	2,082,841	10,376,982	55.14	188,193
2000	10,416,012.35	1,302,002	1,572,151	8,843,861	56.00	157,926
2001	7,681,860.40	854,607	1,031,927	6,649,933	56.88	116,912
2002	3,889,797.06	379,878	458,698	3,431,099	57.75	59,413
2003	8,538,661.58	716,479	865,139	7,673,523	58.63	130,880
2004	3,920,388.15	274,427	331,367	3,589,021	59.52	60,299
2005	5,499,148.85	309,327	373,508	5,125,641	60.40	84,862
2006	4,574,183.25	192,985	233,027	4,341,156	61.30	70,818
2007	10,270,368.96	290,446	350,710	9,919,659	62.19	159,506
2008	8,931,521.23	125,577	151,633	8,779,888	63.10	139,142
2009	4,009,758.94	0	0-	4,009,759	64.00	62,652
	274,328,760.76	47,615,575	57,495,209	216,833,552		4,092,011

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 53.0 1.49

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 477.10 - DIST. SYSTEMS - MEAS. & REG. ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 26-R2						
NET SALVAGE PERCENT.. 0						
1991	2,339,292.01	1,285,722	1,095,573	1,243,719	11.71	106,210
1992	1,745,450.13	915,017	779,693	965,757	12.37	78,073
1993	217,116.81	108,142	92,149	124,968	13.05	9,576
1994	791,322.82	372,832	317,693	473,630	13.75	34,446
1995	220,484.52	97,776	83,316	137,169	14.47	9,480
1996	213,321.69	88,610	75,505	137,817	15.20	9,067
1997	458,954.49	177,404	151,167	307,787	15.95	19,297
1998	281,767.18	100,678	85,789	195,978	16.71	11,728
1999	344,964.17	112,910	96,211	248,753	17.49	14,223
2000	24,898.85	7,393	6,300	18,599	18.28	1,017
2001	20,730.26	5,509	4,694	16,036	19.09	840
2003	109,102.58	22,030	18,772	90,331	20.75	4,353
2005	37,286.71	5,091	4,338	32,949	22.45	1,468
2006	124,400.01	12,823	10,927	113,473	23.32	4,866
2007	197,737.19	13,614	11,600	186,137	24.21	7,688
2008	40,052.12	1,387	1,182	38,870	25.10	1,549
2009	474,891.32	0	0	474,891	26.00	18,265
	7,641,772.86	3,326,938	2,834,909	4,806,864		332,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 14.5   4.35

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 478.10 - DIST. SYSTEMS - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
1968	320.00	304	216	104	1.00	104
1969	759.00	721	513	246	1.00	246
1970	1,524.00	1,448	1,030	494	1.00	494
1971	2,056.65	1,954	1,391	666	1.00	666
1972	800.00	760	541	259	1.00	259
1973	144.00	137	97	47	1.00	47
1974	82.00	78	56	26	1.00	26
1975	778.69	740	527	252	1.00	252
1976	189.74	179	127	63	1.10	57
1977	3,379.78	3,152	2,243	1,137	1.35	842
1978	877.00	808	575	302	1.58	191
1982	1,800.00	1,577	1,122	678	2.48	273
1983	638.00	551	392	246	2.73	90
1984	3,093.08	2,631	1,872	1,221	2.99	408
1985	3,018.58	2,524	1,796	1,223	3.28	373
1986	1,263.80	1,037	738	526	3.59	147
1987	11,574.42	9,288	6,610	4,964	3.95	1,257
1988	346.40	271	193	153	4.34	35
1989	12,306.72	9,365	6,665	5,642	4.78	1,180
1990	395,049.52	291,151	207,195	187,855	5.26	35,714
1992	588,267.13	401,492	285,719	302,548	6.35	47,645
1993	614,141.86	400,728	285,175	328,967	6.95	47,333
1994	1,334,965.81	828,346	589,486	745,480	7.59	98,219
1995	987,917.65	579,908	412,687	575,231	8.26	69,641
1996	877,201.89	484,215	344,588	532,614	8.96	59,444
1997	864,276.82	445,967	317,369	546,908	9.68	56,499
1998	878,861.69	420,535	299,270	579,592	10.43	55,570
1999	822,428.01	361,457	257,228	565,200	11.21	50,419
2000	490,014.73	195,761	139,312	350,703	12.01	29,201
2001	405,230.68	145,275	103,384	301,847	12.83	23,527
2002	310,888.36	98,396	70,023	240,865	13.67	17,620
2003	779,133.76	213,093	151,646	627,488	14.53	43,186
2004	810,497.69	186,009	132,372	678,126	15.41	44,006
2005	457,283.54	84,597	60,203	397,081	16.30	24,361
2006	991,217.82	138,275	98,402	892,816	17.21	51,878
2007	665,905.74	62,262	44,308	621,598	18.13	34,286
2008	625,608.19	29,404	20,925	604,683	19.06	31,725
2009	412,392.17	0	0	412,392	20.00	20,620
	13,356,234.92	5,404,396	3,845,996	9,510,239		847,841

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 11.2   6.35

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. 0						
1991	17,830.39	7,997	3,767	14,063	11.03	1,275
1993	3,357.00	1,397	658	2,699	11.68	231
1994	316,574.63	126,313	59,497	257,078	12.02	21,388
1995	2,428,156.82	926,342	436,331	1,991,826	12.37	161,021
1996	68,172.59	24,781	11,672	56,501	12.73	4,438
1997	6,164.95	2,127	1,002	5,163	13.10	394
1998	46,603.24	15,193	7,156	39,447	13.48	2,926
2000	24,299.82	6,925	3,262	21,038	14.30	1,471
2001	130,955.23	34,310	16,161	114,794	14.76	7,777
2002	772,536.77	183,477	86,423	686,114	15.25	44,991
2003	23,861.40	5,035	2,371	21,490	15.78	1,362
2009	6,417.00	0	0	6,417	20.00	321
	3,844,929.84	1,333,897	628,300	3,216,629		247,595

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 13.0 6.44

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R1.5						
NET SALVAGE PERCENT.. 0						
2004	46,625.78	4,207	5,809	40,817	40.94	997
2005	40,973.52	2,968	4,099	36,875	41.74	883
2006	58,228.15	3,170	4,377	53,851	42.55	1,266
2007	42,140.38	1,536	2,121	40,019	43.36	923
2008	124,838.13	2,275	3,142	121,696	44.18	2,755
2009	666,905.07	0	0-	666,905	45.00	14,820
	979,711.03	14,156	19,548	960,163		21,644

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 44.4 2.21

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 482.30 - GENERAL PLANT - STRUCTURES (LEASED)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R0.5						
NET SALVAGE PERCENT.. 0						
1991	4,949.99	2,569	3,780	1,170	9.62	122
1993	45,336.00	21,195	31,184	14,152	10.65	1,329
1994	12,703.61	5,602	8,242	4,462	11.18	399
1995	11,004.50	4,556	6,703	4,302	11.72	367
1996	4,958.49	1,916	2,819	2,139	12.27	174
1997	13,512.49	4,844	7,127	6,385	12.83	498
1998	28,591.42	9,435	13,882	14,709	13.40	1,098
1999	12,000.00	3,612	5,314	6,686	13.98	478
2000	14,243.55	3,874	5,700	8,544	14.56	587
2001	2,263.75	549	808	1,456	15.15	96
2002	20,305.62	4,315	6,349	13,957	15.75	886
2003	98,974.22	18,112	26,648	72,326	16.34	4,426
2004	40,161.45	6,145	9,041	31,120	16.94	1,837
2005	51,431.98	6,300	9,269	42,163	17.55	2,402
2006	1,414.32	131	193	1,221	18.15	67
2007	25,159.00	1,547	2,276	22,883	18.77	1,219
2008	4,936.81	153	225	4,712	19.38	243
2009	7,353.74	0	0-	7,354	20.00	368
	399,300.94	94,855	139,560	259,741		16,596

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 15.7 4.16

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 5-L0.5						
NET SALVAGE PERCENT.. 20						
1998	52,404.55	30,856	26,497	15,427	1.32	11,687
1999	123,375.15	69,682	59,839	38,861	1.47	26,436
2000	232,479.00	124,981	107,326	78,657	1.64	47,962
2001	226,751.71	114,646	98,451	82,950	1.84	45,082
2002	395,288.84	185,311	159,135	157,096	2.07	75,892
2003	340,697.56	146,091	125,455	147,103	2.32	63,406
2004	253,946.35	97,515	83,740	119,417	2.60	45,930
2005	547,511.72	182,212	156,473	281,536	2.92	96,416
2006	884,309.06	244,777	210,201	497,246	3.27	152,063
2007	378,491.03	79,332	68,126	234,667	3.69	63,595
2008	555,222.52	66,627	57,215	386,963	4.25	91,050
2009	731,814.99	0	0-	585,452	5.00	117,090
	4,722,292.48	1,342,030	1,152,458	2,625,376		836,609

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 3.1   17.72

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-L0.5						
NET SALVAGE PERCENT.. 15						
1992	45,945.36	25,502	33,739	5,315	3.47	1,532
1993	25,739.25	13,827	18,293	3,585	3.68	974
1995	19,242.50	9,601	12,702	3,654	4.13	885
1998	81,554.79	35,215	46,588	22,734	4.92	4,621
2003	86,148.38	25,263	33,422	39,804	6.55	6,077
2005	20,038.14	4,462	5,903	11,129	7.38	1,508
2006	20,886.44	3,746	4,956	12,797	7.89	1,622
2007	12,040.27	1,545	2,044	8,190	8.49	965
2008	9,811.01	684	905	7,434	9.18	810
	321,406.14	119,845	158,552	114,643		18,994

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 6.0   5.91

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-R1.5						
NET SALVAGE PERCENT.. 10						
2004	175,547.50	82,608	44,943	113,050	3.34	33,847
2006	66,492.85	19,834	10,791	49,053	4.68	10,481
2007	136,392.75	27,707	15,073	107,680	5.42	19,867
2008	86,379.26	8,995	4,894	72,847	6.19	11,768
2009	393,165.59	0	0	353,849	7.00	50,550
	857,977.95	139,144	75,701	696,479		126,513

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 5.5   14.75

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 401.01 - FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1987	8,238.78	4,531	1,808	6,431	18.00	357
	8,238.78	4,531	1,808	6,431		357
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT..					18.0	4.33

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 472.00 - DIST. SYSTEMS - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 29-L0.5						
NET SALVAGE PERCENT.. 0						
1991	167.58	59	79	89	18.77	5
1992	37.57	13	17	21	19.14	1
2007	348.51	20	27	322	27.32	12
2009	1,166.13	0	0-	1,166	29.00	40
	1,719.79	92	123	1,597		58

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 27.5 3.37

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 473.00 - DIST. SYSTEMS - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1						
NET SALVAGE PERCENT.. 0						
1990	258,896.21	69,384	55,772	203,124	36.60	5,550
1991	27,567.15	7,013	5,637	21,930	37.28	588
1992	87,832.22	21,168	17,015	70,817	37.95	1,866
1993	200,435.31	45,579	36,637	163,798	38.63	4,240
1994	142,961.75	30,537	24,546	118,416	39.32	3,012
1995	238,754.52	47,751	38,383	200,372	40.00	5,009
1996	210,053.52	39,112	31,439	178,615	40.69	4,390
1997	263,247.63	45,331	36,438	226,810	41.39	5,480
1998	159,049.17	25,193	20,250	138,799	42.08	3,298
1999	178,165.14	25,727	20,680	157,485	42.78	3,681
2000	170,823.83	22,241	17,878	152,946	43.49	3,517
2001	121,507.41	14,119	11,349	110,158	44.19	2,493
2002	145,368.37	14,828	11,919	133,449	44.90	2,972
2003	183,256.23	16,053	12,903	170,353	45.62	3,734
2004	119,236.78	8,728	7,016	112,221	46.34	2,422
2005	103,048.90	6,059	4,870	98,179	47.06	2,086
2006	192,700.94	8,517	6,846	185,855	47.79	3,889
2007	189,060.38	5,596	4,498	184,562	48.52	3,804
2008	222,293.92	3,290	2,645	219,649	49.26	4,459
2009	459,543.27	0	0-	459,543	50.00	9,191
	3,673,802.65	456,226	366,721	3,307,082		75,681

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 43.7   2.06

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 474.00 - DIST. SYSTEMS - METERS/REG. INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-R2.5						
NET SALVAGE PERCENT.. 0						
1990	123,827.24	85,497	67,801	56,026	6.81	8,227
1991	16,941.71	11,243	8,916	8,026	7.40	1,085
1992	31,063.77	19,739	15,654	15,410	8.02	1,921
1993	43,452.24	26,308	20,863	22,589	8.68	2,602
1994	38,808.20	22,297	17,682	21,126	9.36	2,257
1995	46,380.66	25,151	19,945	26,436	10.07	2,625
1996	45,095.62	22,958	18,206	26,890	10.80	2,490
1997	62,955.92	29,904	23,715	39,241	11.55	3,397
1998	66,159.06	29,080	23,061	43,098	12.33	3,495
1999	54,627.05	22,025	17,466	37,161	13.13	2,830
2000	41,971.77	15,358	12,179	29,793	13.95	2,136
2001	28,803.36	9,453	7,497	21,306	14.78	1,442
2002	30,673.05	8,867	7,032	23,641	15.64	1,512
2003	76,840.80	19,176	15,207	61,634	16.51	3,733
2004	49,626.67	10,399	8,247	41,380	17.39	2,380
2005	12,722.43	2,146	1,702	11,020	18.29	603
2006	19,319.73	2,459	1,950	17,370	19.20	905
2007	39,483.19	3,356	2,661	36,822	20.13	1,829
2008	62,861.63	2,686	2,130	60,732	21.06	2,884
2009	456,963.88	0	0-	456,964	22.00	20,771
	1,348,577.98	368,102	291,914	1,056,664		69,124

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 15.3 5.13

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 475.00 - DIST. SYSTEMS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 64-R2						
NET SALVAGE PERCENT.. 0						
1990	1,263,950.80	324,684	399,117	864,834	47.56	18,184
1991	95,296.76	23,258	28,590	66,707	48.38	1,379
1992	369,619.50	85,415	104,996	264,624	49.21	5,377
1993	89,726.51	19,571	24,058	65,669	50.04	1,312
1994	182,140.82	37,339	45,899	136,242	50.88	2,678
1995	415,392.63	79,706	97,978	317,415	51.72	6,137
1996	223,060.83	39,836	48,968	174,093	52.57	3,312
1997	186,645.53	30,854	37,927	148,719	53.42	2,784
1998	330,836.75	50,247	61,766	269,071	54.28	4,957
1999	30,965.42	4,287	5,270	25,695	55.14	466
2000	848,693.63	106,087	130,407	718,287	56.00	12,827
2001	2,053,135.21	228,411	280,774	1,772,361	56.88	31,160
2002	322,274.04	31,473	38,688	283,586	57.75	4,911
2003	165,988.49	13,928	17,121	148,867	58.63	2,539
2004	117,608.73	8,233	10,120	107,489	59.52	1,806
2005	104,449.95	5,875	7,222	97,228	60.40	1,610
2006	68,528.34	2,891	3,554	64,974	61.30	1,060
2007	32,353.74	915	1,125	31,229	62.19	502
2008	105,722.24	1,486	1,826	103,896	63.10	1,647
2009	1,526,706.98	0	0	1,526,706	64.00	23,855
	8,533,096.90	1,094,496	1,345,406	7,187,690		128,503

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 55.9 1.51

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 477.10 - DIST. SYSTEMS - MEAS. & REG. ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 26-R2						
NET SALVAGE PERCENT.. 0						
1990	13,644.21	7,835	7,205	6,439	11.07	582
1996	73.00	30	28	45	15.20	3
2007	80,649.14	5,553	5,107	75,542	24.21	3,120
2009	485,566.33	0	0-	485,566	26.00	18,676
	579,932.68	13,418	12,340	567,593		22,381

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 25.4 3.86

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 477.20 - DIST. SYSTEMS - TELEMETRY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-R1.5						
NET SALVAGE PERCENT.. 0						
2009	2,255.96	0	0	2,256	27.00	84
	2,255.96	0	0	2,256		84

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 26.9 3.72

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 478.10 - DIST. SYSTEMS - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
1981	1,059.83	941	595	465	2.24	208
1984	40.00	34	21	19	2.99	6
1985	23.03	19	12	11	3.28	3
1986	594.94	488	309	286	3.59	80
1990	33,248.91	24,504	15,494	17,755	5.26	3,375
1992	8,301.19	5,666	3,583	4,718	6.35	743
1994	16,747.69	10,392	6,571	10,177	7.59	1,341
1995	33,939.95	19,923	12,597	21,343	8.26	2,584
1996	19,928.49	11,001	6,956	12,972	8.96	1,448
1997	46,396.10	23,940	15,137	31,259	9.68	3,229
1998	16,608.35	7,947	5,025	11,583	10.43	1,111
1999	18,328.91	8,056	5,094	13,235	11.21	1,181
2000	12,077.38	4,825	3,051	9,026	12.01	752
2001	13,001.88	4,661	2,947	10,055	12.83	784
2003	32,129.76	8,787	5,556	26,574	14.53	1,829
2005	59,873.95	11,077	7,003	52,871	16.30	3,244
2006	17,414.89	2,429	1,536	15,879	17.21	923
2007	31,329.80	2,929	1,852	29,478	18.13	1,626
2008	49,745.55	2,338	1,478	48,268	19.06	2,532
2009	32,226.53	0	0	32,227	20.00	1,611
	443,017.13	149,957	94,817	348,200		28,610

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 12.2 6.46

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 482.10 - DIST. SYSTEMS - SYSTEM INSTRUMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0.5						
NET SALVAGE PERCENT.. 0						
1990	321.21	149	167	154	10.72	14
1993	4,919.17	2,046	2,295	2,624	11.68	225
1996	800.00	291	326	474	12.73	37
1997	1,413.15	488	548	865	13.10	66
1999	674.08	206	231	443	13.88	32
	8,127.61	3,180	3,567	4,560		374

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 12.2   4.60

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 5-L0.5						
NET SALVAGE PERCENT.. 20						
2005	46,952.53	15,626	25,638	11,924	2.92	4,084
2008	54,014.14	6,482	10,636	32,575	4.25	7,665
2009	53,341.89	0	0-	42,674	5.00	8,535
	154,308.56	22,108	36,274	87,173		20,284

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 4.3 13.15

FORTISBC ENERGY (WHISTLER) INC.

ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2009

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-L0.5						
NET SALVAGE PERCENT.. 15						
1992	3,290.41	1,826	2,722	75	3.47	22
1993	38,650.75	20,763	30,957	1,896	3.68	515
1996	21,482.50	10,262	15,300	2,960	4.38	676
1997	14,525.28	6,618	9,867	2,479	4.64	534
2006	17,307.25	3,104	4,628	10,083	7.89	1,278
	95,256.19	42,573	63,474	17,493		3,025

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT.. 5.8   3.18

Appendix E-2

ASSET RETIREMENT OBLIGATIONS REPORT

1 INTRODUCTION

In the utility industry, significant investments are required in infrastructure. Along with these investments comes an obligation to eventually remove the plant assets from service, and in some cases, remediate the impacted site. This paper discusses historical and recommended treatment for these asset removal costs and asset retirement obligations for the Fortis BC Utilities (consisting of FortisBC Inc. and the FortisBC Energy Utilities (consisting of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW")).

In this paper, the following definitions are used unless otherwise noted:

- Asset removal costs or asset retirement costs - costs incurred in the retirement of a long-lived asset.
- Asset retirement obligation – obligation to incur asset removal costs or asset retirement costs.
- Negative salvage – asset removal costs less any salvage proceeds received on sale.
- Retirement – other-than-temporary removal from service, including sale, abandonment, recycling or disposal.

The remainder of this paper is organized as follows:

Accounting Background – a discussion of the evolution of relevant accounting principles as they relate to Asset Removal Costs and Asset Retirement Obligations;

Regulatory Background – a discussion of the historical regulatory treatment of Negative Salvage and Asset Retirement Obligations;

Options for Collection of Negative Salvage Costs – summarizes the more commonly accepted methods of collecting asset removal costs from utility customers; and

Summary and Recommendations – recommended treatment for the Fortis BC Utilities for 2012 forward.

2 ACCOUNTING BACKGROUND

2.1 Canadian Generally Accepted Accounting Principles ("GAAP") Prior to 2004

Under CICA Handbook Section 3060 Capital Assets, accounting for asset retirement costs consisted of creating a provision for asset retirement costs on an entity's balance sheet that would increase every year until the asset is decommissioned. The annual increase to the liability account on the balance sheet is reflected as depreciation expense on the statement of operations. Actual retirement costs are charged against the liability on the balance sheet as incurred.

2.2 Canadian GAAP 2004 to 2010 and US GAAP 2003 to Present

CICA Handbook Section 3110 Asset Retirement Obligations ("ARO"s) effective January 1, 2004, requires the recognition of all **legal** obligations associated with the retirement of tangible long lived assets. These legal obligations are referred to as AROs. If a reasonable estimate of their fair value can be made, the obligations must be recorded on a company's balance sheet as a liability. If not, they must be disclosed in the notes to the financial statements and may not be recognized until the period in which a reasonable estimate can be made which may not be until they are incurred. This change was consistent with a change to US GAAP that was effective one year earlier, starting January 1, 2003.

At the time an ARO is incurred (an asset is constructed or purchased), an entry is made to increase the asset and create the offsetting ARO liability at the estimated net present value of the obligation. The asset is then depreciated annually, and the ARO is accreted each year by annual interest so that at the time of asset retirement, the removal costs have been fully provided for. Actual retirement costs that were accrued as part of the ARO reduce the ARO liability; retirement costs that were not provided for through AROs are expensed.

2.3 International Financial Reporting Standards ("IFRS")

Effective January 1, 2010 for comparative purposes, the majority of publicly traded Canadian companies will be complying with IFRS (January 1, 2011 for regulated entities that choose to defer adoption by one year). Under IAS 16 Property, Plant and Equipment and IAS 37 Provisions, Contingent Liabilities and Contingent Assets, the financial treatment of AROs is essentially the same as under Canadian GAAP, except that AROs now encompass not only **legal** obligations but also **constructive** obligations. A constructive obligation is an obligation that derives from an entity's actions where by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and as a result, the entity has created a valid expectation that it will discharge that obligation.

3 REGULATORY BACKGROUND

3.1 BC Hydro

Until Fiscal 2004, BC Hydro's regulatory treatment was aligned with Canadian GAAP, such that asset retirement/removal costs were collected through depreciation expense and when costs were incurred they were charged against that provision (called the Future Removal and Site Restoration account or "FRSR").

Then the CICA adopted Section 3110 Asset Retirement Obligations which replaced FRSR accounting. With the change in Canadian GAAP, in its 2005 fiscal year, BC Hydro established a regulatory deferral liability equal to the FRSR balance at March 31, 2004. There are no further additions to this account through depreciation expense collected from customers, but all removal costs are charged against this account as incurred, unless these costs relate to an ARO. BC Hydro has created an ARO obligation for those assets where it has determined it has an ARO, and increased the asset value accordingly. Each year, the depreciation of the asset and the accretion of the liability are included in rates. When actual retirement costs are incurred in relation to ARO assets, the costs are charged against the liability. If the costs are in excess of the liability, they will be applied instead against the FRSR liability. When the FRSR liability is depleted, non-ARO removal costs will be expensed. The following is an excerpt from BC Hydro's 2009 Annual Report describing the accounting for AROs:

"Asset retirement obligations are legal obligations associated with the retirement of long-lived assets. A liability is recorded in the period in which the obligation is incurred at the present value of the estimated future costs when a reasonable estimate of the fair value can be made. When a liability is initially recorded, BC Hydro capitalizes the costs by increasing the carrying value of the associated long-lived asset. The liability is adjusted for the passage of time through accretion (interest) expense and the capitalized cost is amortized over the useful life of the associated asset. Actual costs incurred upon settlement of an asset retirement obligation are charged against the related liability to the extent of the accrued balance. Any difference between the actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized as a gain or loss in earnings at that time."

The initial balance in the FRSR liability for Fiscal 2005 was $251 million; at the end of fiscal 2010 BC Hydro has forecast the remaining balance to be $150 million. Asset retirement obligations at the end of F2009 were $5 million and relate to only three assets.

Additionally, in March of 2010, BC Hydro filed an application with the British Columbia Utilities Commission ("BCUC") for Approval to Establish a Regulatory Asset Regarding Liability Provision for Environmental Compliance and Remediation. The liability is estimated at $375 million, and is required to record the costs BC Hydro will likely incur to (i) comply with the federal PCB Regulations enacted under the *Canadian Environmental Protection Act, 1999*, and (ii) remediate environmental contamination at one of BC Hydro's properties. The recording of the loss provision is required under CICA Handbook Section 3290 Contingencies. The component of that liability that is considered to be an ARO is estimated at $32 million, which is the part of the obligation that relates to removal costs for assets (equipment removal, transportation and destruction costs).

3.2 FortisBC Inc. ("FBC")

FBC's depreciation rates prior to 2005 did not include a component of negative salvage.

The 2005 Depreciation Study included in FBC's 2006 Revenue Requirements was completed on October 11, 2005 by Gannett Fleming stating that "the calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of December 31, 2004." The 2005 Depreciation Study explicitly calculated depreciation rates to include negative salvage. The rates supported a composite depreciation rate of 3.6% for 2006, inclusive of negative salvage, which was included in the Company's 2006 Revenue Requirements. As a result of the 2006 Negotiated Settlement Process ("NSP"), BCUC Order No. G-58-06, Appendix 1, pages 8 and 9 stated the following:

- The Company and Participants agreed to change the proposed depreciation rates for six accounts which…and are adjusted to 3.0% to reflect longer average service lives for those assets.
- The Company and the Participants hold differing views on negative salvage values in the depreciation. The parties agree to defer the analysis of the issue of negative net salvage value in the depreciation study for the term of the PBR ending in 2008 or 2009.
- The parties did not agree that the findings of the Depreciation Study were otherwise appropriate and no precedent value is attached to the Depreciation Study.

As part of the approval of the 2009 Revenue Requirements process no changes were made to the original assumptions in the 2006 NSP regarding the issue of negative salvage value in depreciation rates. As a result FBC has not been collecting negative salvage in its depreciation rates.

For 2010 and 2011, any asset removal costs incurred continue to be charged against accumulated depreciation with recovery from customers to be settled through updated depreciation rates in 2012.

FBC does recognize that it has some AROs but that the obligations cannot be reasonably estimated, so no amounts have been recorded for regulatory purposes. Starting in 2010, FBC has recognized, for external financial reporting purposes only, an ARO relating to the removal of PCBs from certain electrical equipment under current regulations. Under either IFRS or US GAAP, FBC expects that it will not be required to record any additional AROs at this time, and that any amounts being collected from customers for asset removal costs in advance of the incurrence of those expenditures would be classified as a regulatory liability. For financial reporting purposes in 2010 and 2011, no regulatory liability is recorded on the balance sheet, consistent with the regulatory treatment.

3.3 FortisBC Energy Utilities ("FEU")

Historical practice for the FEU has been to include estimates for negative salvage recoveries as a component of depreciation rates, although these amounts have not been separately tracked in accumulated depreciation. For FEVI, negative salvage costs have been approved by the BCUC for collection from customers for a number of accounts, based on the depreciation rates implemented in 2003 resulting from the Gannett Fleming 2001 Review of Depreciation. For FEI, although negative salvage has been included as a component of depreciation rates in the depreciation studies that have been completed, the results of the studies were never implemented in customer rates except for a select few asset classes, so it is less clear how much, if any, negative salvage has been collected in rates.

The practice of including negative salvage in depreciation estimates was aligned with Canadian GAAP under Section 3060 until 2004, and the FEU had not applied for or been ordered to change the treatment from that time until 2010. Even though it represented a departure from GAAP during that time period, it was in accordance with rate-regulated accounting. With the Negotiated Settlement Agreements resulting from FEI's and FEVI's 2010 and 2011 Revenue Requirements Applications, negative salvage was removed as a component of depreciation being recovered from customers, and instead asset removal costs are being recovered on a cash basis as the costs are incurred, with a deferral account to capture any variances from the estimated asset removal costs included in rates.

The FEU have not historically recorded any AROs under Canadian GAAP since it was determined that no material legal obligations of this nature existed around their long-lived assets, or if they did exist the amount on a discounted basis would be immaterial. Under IFRS or US GAAP, and consistent with FBC and the Fortis Inc. group of companies, the FEU continue to expect that they will not be required to record any additional AROs, and that any amounts being collected from customers for asset removal costs in advance of the incurrence of those expenditures would be classified as a regulatory liability. For financial reporting purposes in 2010 and 2011, no regulatory liability is recorded on the balance sheet, consistent with the regulatory treatment.

3.4 Federal Energy Regulatory Commission ("FERC")

At the time that US GAAP changed to recognize AROs, the FERC revised its Uniform System of Accounts effective 2004 to include asset retirement obligation assets and related liabilities, and also the depreciation and accretion expense related to these amounts in the determination of rates. At the same time, the FERC clarified that for costs of removal that do not constitute a legal obligation (and therefore do not qualify as an ARO), utilities would continue to record the collection of costs as a component of depreciation expense, but that the accrued accumulated removal costs for other than legal retirement obligations must be separately identified and quantified in subsidiary records of accumulated depreciation to facilitate external reporting and for regulatory analysis, and rate setting purposes.

3.5 National Energy Board

In 2008, the National Energy Board ("NEB") initiated the Land Matters Consultation Initiative ("LMCI"). There were four streams to the initiative, with Stream 3 dealing with financial matters. After a series of consultations and written submissions, the NEB released its report and reasons for decision in May of 2009, applicable to all pipelines regulated under the NEB Act.

The following terms are used in the NEB Decision[1]:

Abandon – To permanently cease operation such that the cessation results in the discontinuance of service.

Decommission – To permanently cease operation such that the cessation does not result in the discontinuation of service, for example, when a tank is removed from operation on a pipeline and the pipeline continues to operate without the tank.

Perpetual Maintenance – The ongoing use of methods to maintain and abandoned pipeline to avoid collapse, subsidence, corrosion or other adverse impacts. This is sometimes referred to as continuing maintenance.

Terminal Negative Salvage – The costs incurred in the abandonment of pipeline facilities less any value realized from the disposition of such facilities.

The Panel in the LMCI recommended the following[2]:

"*The Panel recommends the following as key principles and considerations:*

1. *It is in the public interest that all pipelines regulated by the NEB be abandoned safely and effectively.*
2. *Pipeline companies are ultimately responsible for the full costs of constructing, operating and abandoning their pipelines, and the Board will hold the regulated company responsible for these costs.*
3. *The Board regulates using a goal-oriented, risk-based lifecycle approach; it does not subscribe to the concept of elimination of risk.*
4. *Landowners will not be liable for costs of pipeline abandonment.*

[1] Land Matters Consultation Initiative Stream 3 RH-2-2008 Pages 8 and 9
[2] Land Matters Consultation Initiative Stream 3 RH-2-2008 Pages 32 and 33

5. *At this time, the use of pooling as a general mechanism for setting aside funds to cover the costs of abandonment is not efficient from a regulatory or economic perspective.*
6. *Timing of abandonment of a pipeline for the purpose of estimating future abandonment costs should be the shorter of anticipated economic life or physical life.*
7. *The removal of all large-diameter abandoned pipe from agricultural land is not a prudent or effective approach for the purpose of establishing preliminary abandonment cost estimates.*
8. *Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system.*
9. *Funds for abandonment costs should be collected and set aside in a transparent manner.*
10. *Funds for abandonment costs should not be collected as part of depreciation and should be a separate element of cost of service.*
11. *Any funds set aside for abandonment must be held in such a manner that they can only be used for the purposes of abandonment and abandonment planning.*
12. *The Board, as an independent and quasi-judicial tribunal, does not promote the development of tax policies or initiatives."*

The Panel, in reviewing key principles and considerations, also stated:[3]

"*The Panel recommends that any process and mechanism for setting aside the funds for abandonment have the following attributes:*

- *funds must be maintained in a segregated account and not be commingled with a company's general corporate funds;*
- *funds must be managed by an independent, third party;*
- *funds collected must be protected from creditors;*
- *funds must be protected from misuse or use for a purpose other than abandonment;*
- *regular reviews (at least every five years) of the amount of funds set aside and disbursed from the segregated account must be incorporated, and regular reporting to the Board and stakeholders must be built in;*
- *funds must be segregated by pipeline;*
- *funds must be subject to Board audit, as appropriate;*
- *companies must develop a sound investment policy for abandonment funds as ultimately, accountability for the collection and governance of the funds rests with each pipeline company; and*
- *the process for accessing the funds must be clearly set out in the mechanism."*

[3] Land Matters Consultation Initiative Stream 3 RH-2-2008 Page 41

The Panel recommended that a number of Base Case assumptions form the basis for preparing cost estimates for each pipeline company. The Base Case assumptions have not been included in this document as they are specific to pipelines regulated by the NEB.

4 OPTIONS FOR COLLECTION OF NEGATIVE SALVAGE

As discussed, the collection of negative salvage costs over the life of the related assets is the commonly accepted regulatory practice in both the United States and Canada. It is accepted by the US FERC in its Uniform System of Accounts and by the National Association of Regulatory Utility Commissioners in their Public Utilities Depreciation Practices. In Canada, it is an accepted practice for gas distribution utilities by the following Boards[4]:

- Alberta Utilities Commission
- Saskatchewan Rate Review Panel
- Manitoba Public Utilities Board
- Ontario Energy Board
- Régie de l'énergie du Québec
- Nova Scotia Utility and Rate Board

Throughout the regulatory guidance and decisions is the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal, hence, if current users benefit from the use of the asset, they should pay their pro rata share of the cost involved in the retirement of the property.

The Fortis BC Utilities consider that goals for a regulatory policy on negative salvage costs include:

1. Distribute costs to ratepayers equitably over time;
2. Improve utility accountability for negative salvage costs collected from ratepayers;
3. Ensure that funds for asset removal are available at the time they are needed;
4. Minimize administrative costs related to implementation, maintenance and tracking of negative salvage costs.

Keeping these goals in mind and based on a review of the above policies, consultation with Gannett Fleming[5], and other available literature, there are four possible approaches to collection of negative salvage costs that will be discussed here. In all cases, it is expected that the resulting regulatory liability related to negative salvage liabilities would be tracked separately by asset class and disclosed as a separate line in rate base and in external financial reporting to assist with goal number two.

[4] Responses to BCOAPO IRs 1.7.4, 2.1.1 and 2.1.2 in the 2010-2011 Terasen Gas (Whistler) Inc. 2010-2011 Revenue Requirements and Rates Application
[5] See Gannett Fleming 2009 Depreciation Study included in Appendix E-1

4.1 Method 1 Pay as You Go

Under this method, negative salvage costs are collected from customers as they are actually incurred, with a deferral account if variances from forecasts are potentially significant.

Advantages:

- Easy to explain and administer.
- Only short-term estimation is involved in determining negative salvage costs since only projecting actual costs to be incurred for the period of the revenue requirement (usually based on previous experience with any adjustments for known events).

Disadvantages:

- Costs are not appropriately borne by the customers that are using the assets. The actual costs of abandonment are borne by today's customers who have not had use of the asset over its life.
- Amount included in rate determinations will differ from actual costs incurred; therefore likely to require deferral accounts to capture forecast vs. actual differences in removal costs.
- Customers are charged for costs relating to assets that have been removed from service.
- Risk of stranded assets, particularly in an environment of declining use rates and customer base.

4.2 Method 2 Depreciation Basis (traditional)

This is the traditional method employed by BC Utilities in their depreciation studies. There are variations to account for various price escalators, but the basic premise is the same. Under this method, the negative salvage percentages are a component of depreciation rates, and are calculated as the expected cost to remove the asset today divided by the cost to install that asset originally. The resulting rate is then incorporated into the depreciation rate as follows:

Assume an asset that originally cost $1,000 and an average service life of 50 years has estimated removal costs in today's dollars of $500. Therefore, the negative salvage percentage is 50%. To convert this into a depreciation rate, we use the following formula:

$$\frac{(1 - \text{net salvage percentage})}{\text{Avg. Service Life}} \times 100 = \frac{(1 - 50\%)}{50} \times 100 = 1\%$$

To summarize, if we collect 1% of $1,000 or $10 each year for 50 years then at the end of 50 years we will have $500 or enough to pay the negative salvage (removal) costs.

In this method, the only estimate being determined (other than the average service life which has already been determined as part of the depreciation study) is the estimated removal costs for the asset class. This estimate is usually determined based on a combination of a study of historical records adjusted to reflect the projects currently underway, and interviews with company personnel.

Since the numerator (removal costs) is estimated in today's dollars and the denominator (original cost) is in historical dollars, the calculation of the negative salvage percentage inherently recognizes the inflation that is expected between the time of original installation of the property and the time it will be removed or abandoned. As long as inflation is consistent with historical trends, the relationship should also hold true for the future.

To adjust for variations in the impact of inflation over time, a variation on the traditional approach called the Constant Dollar Net Salvage ("CDNS") has been used in the past. The CDNS approach brings both the original cost and the removal costs to today's dollars, removing all impacts of inflation. Then a forward looking estimate of the rate of inflation is applied based on current long term economic data for local labour markets to provide a more accurate indication of the true expected removal costs, and more closely align with accepted accounting methodologies.

Advantages:

- Collects removal costs from customers that benefit from the assets.
- Easy to administer.
- No deferral accounts required.
- Familiar to regulators and customers as it reflects the traditionally accepted model of collecting removal costs.

Disadvantages:

- Involves long-term estimates of removal costs, and either a dependence on the continuation of historical inflation rates, or estimating future inflation rates.
- More difficult to verify/replicate the calculations that collect the rates (sampling could be used).
- Requires periodic re-estimating.

4.3 Method 3 ARO

This method would mirror the calculation of an ARO under GAAP. Under this method, asset removal costs for each asset class would be estimated going out for the remaining asset class life by year, and then these removal costs would be discounted to today's dollars. These estimated amounts would then be added to the asset and an equal and offsetting ARO liability would be created. Each year, the asset would be depreciated and the liability would be accreted so that at the time the asset is removed the asset is fully depreciated and the liability fully funds the removal costs incurred.

Advantages:

- Collects removal costs from customers that benefit from the assets.
- Familiar to accountants as it is follows GAAP for AROs.

Disadvantages:

- The Fortis BC Utilities do not believe that the ongoing interim removal costs that are used in the calculation of negative salvage rates represent AROs; the same accounting treatment may cause confusion in differentiating the two.
- Difficult to understand and follow.
- Complex to record and track; additional costs likely to be incurred.
- Involves estimates of removal costs and also long-term estimates of inflation rates.
- Requires periodic re-estimating and annual adjustment to accretion rates.
- A further refinement of the ARO methodology is to segregate funds for future asset removals in a separate independent fund, similar to what is proposed by the NEB for pipelines. Although this methodology may work in situations where there is a single long-term asset with a significant decommissioning cost to be incurred, it could not be applied to the more common situation, where there are ongoing removal costs for many individual assets that make up a larger system. This is the case for the Fortis BC Utilities, and we believe that using segregated funds would not be an efficient methodology for administering the funds, and would be administratively expensive and burdensome.

4.4 Method 4 Hybrid

The possibility exists of combining any of the three above methods. One option would be that asset retirement costs for specific designated assets follow the ARO methodology; all other negative salvage estimates would follow the traditional depreciation methodology.

5 SUMMARY AND RECOMMENDATION

GAAP recommends that Canadian utilities record AROs where required. The Fortis BC Utilities will continue to comply with GAAP and record AROs where necessary under GAAP. In addition, any asset removal costs (negative salvage) collected from ratepayers but not yet incurred will be recorded as a regulatory liability.

Regulatory practice in the United States and throughout most of Canada allows for the collection of negative salvage costs through rates over the life of the associated assets. The most common practice is to recover these costs as a component of depreciation rates, and record the difference between the amounts collected and the amounts expended as a reduction in rate base.

There are a number of methods that can be used to calculate and track the collection of funds for removal costs, which can be held in a segregated fund similar to pension trust funds, four of which have been discussed in this paper. The first three methods achieve the goals of regulatory policy on removal costs to varying degrees, with Method #4 being a hybrid. The ranking of the four methods as compared to the stated regulatory policy goals is summarized in the following table. As stated above, the four goals are:

1. Distribute costs to ratepayers equitably over time;
2. Improve utility accountability for negative salvage costs collected from ratepayers;
3. Ensure that funds for asset removal are available at the time they are needed;
4. Minimize administrative costs related to implementation, maintenance and tracking of negative salvage costs.

Table 1: Ranking of Methods

Method	Goal 1	Goal 2	Goal 3	Goal 4
1 Pay As You Go	No	No	No	Yes
2 Depreciation Basis	Yes	No	Yes	Somewhat
3 ARO	Yes	Yes	Yes	No
4 Hybrid	Yes	Yes	Yes	Somewhat

The recommendation of the Fortis BC Utilities for implementation in their 2012 Revenue Requirements Applications is to adopt a Hybrid Approach. The traditional depreciation approach will be utilized for regulatory assets that require significant removal costs, with funds segregated by asset classes in a separate liability account. In addition, the utilities will continue to review their regulatory assets to determine if any AROs are required to be recorded under GAAP. If AROs are required to be recorded under GAAP for specific assets, the utilities propose to use the ARO methodology for regulatory purposes as well, overall incorporating a Hybrid Approach. All removal costs not provided for under either the traditional depreciation approach or the ARO approach will be expensed as incurred.

Appendix E-3

ASSET LOSS REPORT

1 ANALYSIS OF ASSET RETIREMENT LOSSES

1.1 Introduction

As part of the 2010 Depreciation Study update requested by the BCUC in its decision on FortisBC Energy Inc.'s ("FEI") 2009 RRA, FEI undertook a project to analyze and support the accumulated losses recorded to date. At the end of 2009, the total asset retirement loss balance stood at approximately $149 million with the asset categories, Mains, Services, Regulator and Meter Installation, and Meters accounting for the majority of the losses.

The purpose of this report is to provide:

- An overview of the asset retirement and accounting processes at FEI and how the processes led to the financial gains/losses recorded; and
- Explanations and reasons for the losses recorded for each of the asset categories noted.

1.2 Overview of Asset Retirement Process at FEI

Upon retirement of a fixed asset, the Plant Accounting department is notified. For retirement of recurring plant (Mains, Meters, Services), the plant units retired are provided by Field Operations. To calculate the retirement values, original costs per plant unit are used. If original costs are not known, estimates are used to retire specific plant. A plant retirement request form capturing the specifics of the plant being retired is completed and submitted to Plant Accounting. Each specific plant is identified in terms of its physical characteristics, function, location, etc.

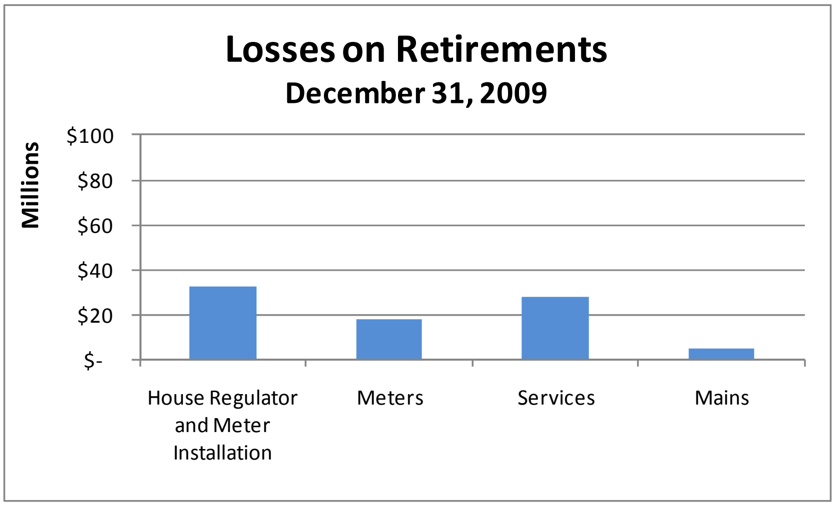
Upon retirement, the service value (i.e. original cost or estimate) of the retired asset is credited to the appropriate capital account with the associated accumulated depreciation amount debited to the accumulated depreciation account, with the difference (remaining net book value) remaining in a component of accumulated depreciation called "accumulated loss". Retirement costs (i.e. labour to dismantle the asset) and salvage proceeds (i.e. scrap value) are allocated also to the accumulated loss component of the accumulated depreciation account.

The treatment of both the removal costs and the remaining net book value of plant on retirement as a component of Accumulated Depreciation is an accepted regulatory accounting practice in accordance with the BCUC Uniform System of Accounts

1.3 Losses by Asset Category

Four asset categories totalling to $138 million account for over 90% of $149 million of the losses recorded to the end of 2009. The $138 million figure includes $54.1 million of removal costs less salvage proceeds. Excluding the removal costs less salvage proceeds, the "unrecovered losses" total to $84.1 million. This represents approximately 4% of the historical cost balance of $2 billion for these four asset categories. The losses by asset class are shown in Table E3-1 below, followed by an analysis of each class.

Table E3-1: Four Asset Categories Contribute to Accumulated Losses to end of 2009



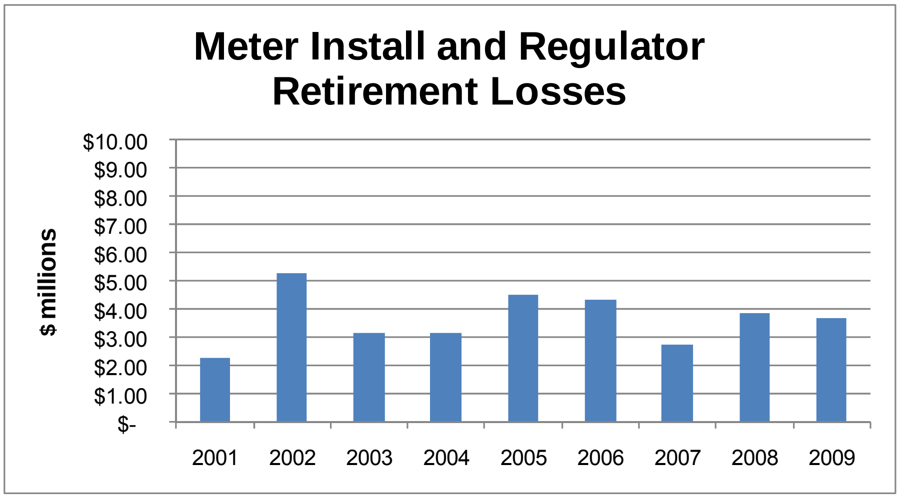
1.3.1 REGULATORS AND METER INSTALLATIONS (ASSET CLASS 474)

This account includes the cost of regulators, and labour and materials used and expenses incurred in the connection with the original installation of regulators and meters for all customer types including residential, commercial and industrial.

At the end of 2009, accumulated losses in this asset class were approximately $32.4 million (excluding removal costs less salvage proceeds of $5.6 million). As a percentage, the $32.4 million accumulated loss represents 22% of the historical cost balance of $148 million.

The following graph shows the losses recorded in this asset category for the years 2001 to 2009. Prior to the year 2001, the gains/losses observed for this asset category were minimal.

Figure E3-1: Losses for Asset Class 474 by Year



Further analysis of the retirement losses suggest that the attributed losses have been amplified as the result of an overstatement of the historic unit costs used for determining the gains/losses on retirements.

Starting in 2001, FEI implemented a process to retire the install labour costs included in this asset category, using the number of meters scrapped and the applicable historical unit costs based on a composite average of the activities being recorded in this account. However, there is a wide disparity in the actual cost for the different types of meter install activities, with a simple residential install costing approximately $60 per install compared to a larger diaphragm meter install for a commercial customer at double or more. For this reason, applying a composite unit cost to determine gains/losses for retirements, particularly a lower cost residential install, has resulted in an overstatement of losses.

Analysis of the losses reported for the recent years 2006 to 2009 show that of the approximately 120,000 meters scrapped during this period, over 90% were for smaller diaphragm meters used for residential customers. Yet, the loss reported on a per meter installed basis ranged from $100 to $150 each, significantly higher than the $60 per meter install stated earlier.

On a retrospective basis, if a revised historic unit cost ranging from $60 to $100 meter install was used for the period 2006 to 2009, the retirement loss recorded for that period would instead range only from $4 to $7 million compared to the actual reported loss of approximately $15 million. Total rate base would remain unchanged as the losses would be reclassified to accumulated depreciation from the asset loss balance.

The preceding analysis suggests that the losses reported of $32 million for the period 2001 to 2009 is likely to be overstated by approximately 50%, reflecting the challenges in coming up with an applicable representative unit cost. This conclusion is corroborated by the $16 million of losses recorded in the Meter asset category during the same time period. It is reasonable to expect retirement losses in the Meter Install (474) asset category to follow and be similar to that of the Meter (478) category. Currently, for 2001 to 2009, the retirement losses for the Meter Install asset category exceed that of the Meter asset category by approximately double ($32 million vs. $16 million). All else equal, the overstatement effect for this account will likely even out over time as future retirements are recorded using a lower unit cost based on an understated remaining cost pool.

The above analysis highlights the challenges with developing a retirement process for a wide and disparate asset category such as the Meter Install. To address this, Gannett Fleming recommends adopting an approach that records new plant additions for this asset class in a separate account, with depreciation calculated using a whole life rate. The existing meter install costs would remain in the current account and continue depreciating at the current depreciation rate, which includes a factor for recovery of the retirement losses. This recommended approach would simplify the retirement process (i.e. no retirement entries required) while still recording the appropriate level of depreciation expense.

1.3.2 METERS (ASSET CLASS 478)

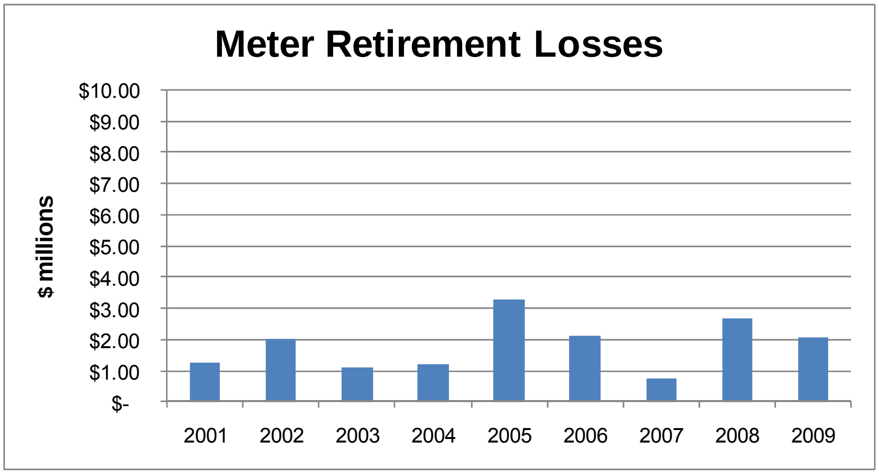
This account includes the cost of meters or devices (including the cost of badging and testing) for use in measuring the quantity of gas delivered to all customer types including residential, commercial and industrial.

Consistent with the industry, FEI currently expects the lives of its residential meter assets to currently last no longer than 15 to 20 years. Commercial and industrial meters, comprising approximately 20 – 25% of the investment in meters however are expected to last beyond 20 years as the larger volume meters are refurbished when they are removed for testing.

At the end of 2009, accumulated losses in this asset class were approximately $18.4 million (excluding removal costs less salvage proceeds of ($2.1) million). As a percentage, the $18.4 million accumulated loss represents approximately 9% of the historical cost balance of $205 million.

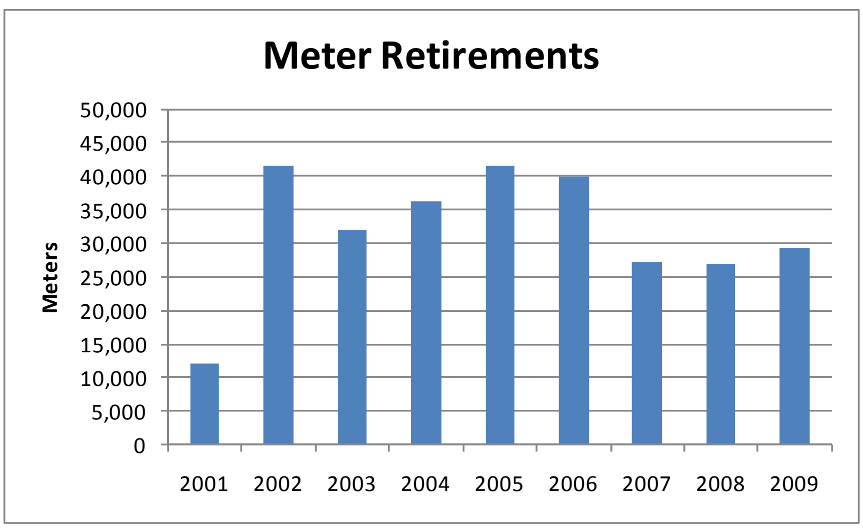
The following graph shows the losses recorded in this asset category for the period 2001 to 2009.

Figure E3-2: Losses for Asset Class 478 by Year



The following graph shows the numbers of meters retired for the years 2001 to 2009.

Figure E3-3: Number of Meters Retired by Year



Meters are retired and scrapped when they have reached the end of their useful lives. After the initial install of meters for new customers, meters subsequently are subject to a meter exchange program where in-service meters are removed and replaced with new or repaired meters to maintain accurate measurement as required by the Electricity and Gas Inspection Act of Canada.

For residential gas meters, upon installation, a seal with an associated expiry date is attached to the meters. A year prior to the expiration of the seal, the meters must be evaluated to ensure the accuracy is within federally regulated tolerances. A representative sample is extracted from pre-determined groups of meters according to Measurement Canada regulations. The sample meters are tested under strictly controlled conditions in certified test facilities with the test data analyzed using government mandated statistical methods. The test results are then used to determine if the meters from the group of which the sample was withdrawn are legally permitted to remain in service. The greater the level of error observed in the sampled meters, the shorter the time period of the seal extension as directed by the Electricity and Gas Inspection Act of Canada. Where test results fail to meet regulated accuracy requirements, the meter group in question will be removed from the field and replaced, at which time a determination is made whether the removed meters will be retired.

Based on the company's meter retirement data, FEI has observed that the average residential meter life has been less than the 25 – 28 years as previously anticipated. The shorter residential meter life is linked to the increased cost to refurbish residential meters relative to the cost to replace these same meters. In the past, FEI's operating model had residential meters being removed from the field after approximately 14 years in service for refurbishment. The meters were then re-installed with the expectation that these meters would again be removed from the field within another 14 years, for a service life totalling 28 years. However, since then, the cost of labour and materials for retrieval and refurbishment continued to rise with the cost to replace with new meters falling. Consequently, over the last decade, the refurbishment of residential meters has been become uneconomical. As a result, to maximize the full value of these meters, these meters have been allowed to remain in the field until such time they are replaced with a new meter. Recent FEI sampling results indicate that on average residential meters approach the maximum allowable error limit at approximately the 20 year mark.

To a lesser extent, another reason for the early retirement of meters is due to inferior residential meters, arising from manufacturing issues. A notable example is the planned removal of batches of meters installed during the late 1990s, with sample testing showing loss of accuracy at much faster rates than expected. FEI expects that these meters will be required to be removed from service in accordance with ongoing meter sample test results to prevent large scale unscheduled failures.

It is expected that the current 20 year life expectancy for residential meters will continue in the foreseeable future. As such, FEI will continue to require that a certain portion of the meter fleet be exchanged every year (i.e. 1 / 20 years or 5% of the meter fleet).

Finally, in 2005, Measurement Canada began the process of rewriting a number of specifications to reflect a change in approach toward regulation of organizations using custody transfer meters from being less prescriptive to more performance based, with a greater focus upon enforcement. Most recently, Specification SS06 came into effect January 1, 2011 with a required date for full implementation no later than January 1, 2014. This specification is designed to meet Measurement Canada`s goal of greater assurance of compliance with the Electricity and Gas Inspection Regulations among organizations which choose to apply compliance sampling in order to extend the use of their meters. At this time, FEI believes its existing meter fleet management practices will ensure the company remains in compliance with the increased rigor of this specification.

1.3.3 SERVICES (ASSET CLASS 473)

The assets in this class consist of installations of various service pipes for new and existing customers including:

- new and conversion distribution pressure (DP) and intermediate pressure (IP) services to single and multi-family dwellings;
- pre-installed service stubs from mains;
- services extended from stubs;
- vertical header subdivisions (a vertical service line system within a building such as a high-rise);
- DP and IP new or conversion service header mains (distribution mains installed on private property such as multi-family strata owned complexes); and
- DP and IP service header laterals.

FEI expects the lives of its distribution services assets to be within the range of its industry peers, with typical service lives ranging from 40 to 65 years. At the end of 2009, accumulated losses in this asset class were approximately $27.8 million (excluding removal costs less salvage proceeds of $45.8 million). As a percentage, the $27.8 million accumulated loss represents only 4% of the historical cost balance of $664 million.

Reasons that services may be retired earlier than their expected lives and contribute to the retirement losses recorded to date can be classified into two categories - Customer and Safety. The table below provides a summary of the services retired in recent years 2006 to 2009 with the length of the service pipe retired and the associated retirement costs separated into the categories Customer and Safety.

Table E3-2: Most Services Retired Due to Customer Requests

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs	Metres of Services Retired	Retirement Costs
Customer	76,958	$ 4,079,701	76,893	$ 4,235,239	68,959	$ 4,913,276	72,817	$ 4,906,138
Safety	11,303	$ 584,850	30,733	$ 311,291	45,852	$ 471,291	10,811	$ 499,975
Total	88,261	$ 4,664,551	107,626	$ 4,546,530	114,811	$ 5,384,566	83,628	$ 5,406,113

The data above indicates that the majority of retirements expressed in metres of pipe retired and the retirement costs incurred were the result of customer initiated requests.

Customer requests to retire services originate as a result of land development activities and specific requirements of customers. As the demand for housing in the more densely populated regions (i.e. Lower Mainland) increases, existing housing and land are being redeveloped with larger plots of land being subdivided and existing housing demolished to make way for multi-family housing (i.e. townhouses, condos). This is contributing to a shorter useful life observed than originally anticipated. Other customer driven requests include those resulting from homeowners performing building modifications and landscaping activities that often require the retirement of service line assets. To mitigate the rate impact to all customers, FEI seeks to recover the retirement costs from the customer that initiates the work wherever possible.

The other contributor to early service retirements is safety. FEI has a service retirement program to remove inactive services. An inactive service to a premise is a live gas service or meter with no existing customer. These assets continue to attract regular maintenance but are not presently being used for gas delivery. Inactive services are often forgotten by the property owner and represent a significant risk of third party damage. Removal of inactive services initiated by FEI improves the safety of the public, the natural gas delivery system and its employees.

1.3.4 MAINS (ASSET CLASS 475)

This asset class consists of the installation and material costs of new and replacement intermediate pressure and distribution pressure mains from the pressure regulator station to the customer service line including:

- Main extensions and tie-ins to serve new customers;
- Gas main additions or replacements (i.e. system improvements) and tie-ins needed to service increasing demands placed on the system;
- Replacements (i.e. renewals) of portions of existing mains to remove corroded or damaged sections; and

- Replacement of pipe that has been identified as non-compliant due to geographical location (close to highways or bridges) or pipe configuration.

FEI expects the lives of its distribution mains assets to be within the range of its industry peers with typical service lives for mains ranging from 50 to 65 years. At the end of 2009, accumulated losses in this asset class were approximately $5.5 million (excluding removal costs less salvage proceeds of $4.8 million). As a percentage, the $5.5 million accumulated loss represents only 0.6% of the historical cost balance of $861 million.

Reasons that distribution mains may be retired earlier than their expected lives and that contribute to the retirement losses recorded to date can be classified into two categories, Customer and Safety/Reliability. The table below provides a summary of the distribution mains retired in recent years 2006 to 2009 with the length of the mains pipe retired and the associated retirement costs separated into Customer and Safety/Reliability.

Table E3-3: Most Mains Retired for Safety and Reliability Reasons

Reasons for Retirement	2006		2007		2008		2009	
	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs	Metres of Main Retired	Retirement Costs
Customer	1,048	$ 22,981	-	$ 6,083	-	$ -	15	$ 535
Safety/Reliability	26,169	$ 513,060	54,548	$ 525,600	53,832	$ 474,834	21,107	$ 591,413
Total	27,217	$ 536,041	54,548	$ 531,683	53,832	$ 474,834	21,122	$ 591,948

The data above indicates that the majority of retirements, expressed in metres of pipe retired and correlated to the retirement costs are primarily the result of safety/reliability related reasons.

FEI is committed to ensure the safety and reliability of the distribution system. To achieve this, FEI regularly assesses and monitors the health of its distribution mains system, noting factors such as the age and condition of the pipe installed, identified leaks, effectiveness of corrosion prevention and condition of coatings on the pipe. Where warranted, the Company replaces the distribution mains earlier than expected in order to maintain the integrity of the pipe. Where the opportunity permits, FEI schedules mains pipe replacement to coincide with municipal or road construction activities in order to minimize the costs. In the past, high failure rates leading to early retirement of distribution mains have resulted from leaks caused by corrosion in mains installed prior to 1980. Prior construction practices, use of coal tar and asphalt enamel pipe coatings from 1930 to 1970, and use of tape coatings in the 1970s have been contributing factors to earlier retirements.

Customer requests to relocate distribution mains may also lead to earlier retirement than expected. Highway construction, municipality activities and private industry development may result in FEI having to retire and relocate an existing main. To mitigate the rate impact to all customers, FEI seeks to recover the related costs wherever possible from the initiator of the request.

1.4 Conclusion

As the above analysis and explanations indicate, FEI's recorded retirement losses for the asset categories mains, meters and services are reasonable and reflective of the regulations it faces and the environment which it operates in as a natural gas utility.

Appendix F-1

LOCK-OFF AND RECONNECTION REACTIVATION FEE

LOCK-OFF AND RECONNECTION/REACTIVATION FEE

The Companies plan to increase the reconnection/reactivation fee to $100 (regular hours) and $140 (after hours). The proposed change reasonably reflects the cost of providing this service. The proposed fee change also mitigates negative impacts to other ratepayers and reduces the O&M cost per customer for all customers.

The reconnection/reactivation charge applies to customers who request reinstatement of gas service after a disconnection. The fee includes the field cost of performing the disconnect (also known as lock-off or de-activation) and the reconnect (also known as unlock or re-activation and relight) together with a nominal office administrative cost for order creation and review, scheduling and dispatching. FEU plans to increase the reconnection/reactivation fee by $35 (regular hours) and by $35 (after hours) effective January 1, 2012, from the current charge of $65 (regular hours) and $105 (after hours).

Up until the end of 2011, Accenture Business Services for Utilities ("ABSU") (on behalf of CustomerWorks LP) will continue to provide a bundled suite of services which includes: billing, meter reading, customer contact (call centre operations) and credit and collections. A bundled rate per customer is charged for the services and includes the Lower Mainland lock-offs as part of credit and collections services provided. FEU is unable to determine the portion of the bundled rate that is related to the administrative costs to perform the Lower Mainland lock-off activities.

Following expiry of the ABSU contract at the end of 2011, FEU will manage all lock-offs including Lower Mainland lock-offs, starting on January 1, 2012. In response to this upcoming change, it is necessary to review the reconnection/reactivation fee to ensure revenues adequately recover the costs of performing the disconnection, reconnection, and reactivation service. The service is set out in the FortisBC Energy Inc. Tariff – Section 5.4, FortisBC Energy (Vancouver Island) Inc. Tariff – Section 5.4 and FortisBC Energy (Whistler) Inc. Tariff – Section 5.4, as follows:

> ***Reactivation Charges*** *- If*
>
> *(a) Service is terminated*
>
> > *(i) at the request of a Customer, or*
> >
> > *(ii) for any of the reasons described in Section 23 (Discontinuance of Service and Refusal of Service), or*
> >
> > *(iii) to permit Customers to make alterations to their Premises, and*

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year, the applicant for reactivation must pay the greater of

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

A review of the actual and forecast costs of providing this service demonstrates that the current charges of $65 (regular hours) and $105 (after hours) do not adequately recover the disconnection and reconnection/reactivation costs. This is demonstrated in the following four tables which are based on the following assumptions:

- The 2012 – 2013 forecast activities are based on 2010 activities.
- Consistent with the current experience the proportion of relights completed after hours in relation to during working hours will not change significantly.
- Consistent with the current experience, most or all industrial meter unlocks will be done during working hours.
- $3 administration (dispatch) unit cost based on task duration and labour rate.

Table F-1: Fee Increase Required for the Mainland to Recover Cost of Service

Annual Activities for 2012-2013			
Mainland	**Forecast Costs**	**Forecast Activities**	**Unit Cost**
Lock-off Activities	$1,271,544	31,810	$40
Relight Activities - Regular hour	$1,311,349	23,689	$55
Relight Activities - After hour	$433,666	5,569	$78
Administration (Dispatch)	$94,650	31,810	$3
Total Costs	**$3,111,209**		
Recoveries	**Forecast Recoveries**	**Forecast Activities**	**Reconnect Fee**
Reconnects - Regular hour	$2,331,549	23,689	$98.42
Reconnects - After hour	$779,660	5,569	$140.00
Total Recoveries	**$3,111,209**		

Table F-2: Fee Increase Required for Vancouver Island to Recover Cost of Service

Annual Activities for 2012-2013			
Vancouver Island	**Forecast Costs**	**Forecast Activities**	**Unit Cost**
Lock-off Activities	$91,648	1,622	$57
Relight Activities - Regular hour	$127,938	1,870	$68
Relight Activities - After hour	$42,403	350	$121
Administration (Dispatch)	$4,800	1,622	$3
Total Costs	**$266,789**		
Recoveries	**Forecast Recoveries**	**Forecast Activities**	**Reconnect Fee**
Reconnects - Regular hour	$217,789	1,870	$116.46
Reconnects - After hour	$49,000	350	$140.00
Total Recoveries	**$266,789**		

Table F-3: Fee Increase Required for Whistler to Recover Cost of Service

Annual Activities for 2012-2013			
Whistler	**Forecast Costs**	**Forecast Activities**	**Unit Cost**
Lock-off Activities	$2,146	51	$42
Relight Activities - Regular hour	$2,518	61	$41
Relight Activities - After hour	$2,305	14	$165
Administration (Dispatch)	$141	51	$3
Total Costs	**$7,110**		
Recoveries	**Forecast Recoveries**	**Forecast Activities**	**Reconnect Fee**
Reconnects - Regular hour	$5,150	61	$84.42
Reconnects - After hour	$1,960	14	$140.00
Total Recoveries	**$7,110**		

A combined view of the forecast activities, cost and fee analysis is presented below to arrive at a required standard fee.

Table F-4: Fee Increase Required for FEU to Recover Cost of Service

Annual Activities for 2012-2013			
FEU	**Forecast Costs**	**Forecast Activities**	**Unit Cost**
Lock-off Activities	$1,365,338	33,483	$41
Relight Activities - Regular hour	$1,441,805	25,620	$56
Relight Activities - After hour	$478,374	5,933	$81
Administration (Dispatch)	$99,591	33,483	$3
Total Costs	**$3,385,107**		
Recoveries	**Forecast Recoveries**	**Forecast Activities**	**Reconnect Fee**
Reconnects - Regular hour	$2,554,487	25,620	$99.71
Reconnects - After hour	$830,620	5,933	$140.00
Total Recoveries	**$3,385,107**		

A standard reconnect fee of $100 (regular hours) and $140 (after hours) for FEU is required to recover the disconnection, reconnection, and reactivation costs, as shown in Table F-1 below.

Table F-5: Planned Fee Increase to Recover Disconnection, Reconnection/Reactivation Cost of Service

Plan	**Forecast Recoveries**	**Forecast Activities**	**Plan Reconnect Fee Required**
Reconnects - Regular hour	$2,562,000	25,620	$100
Reconnects - After hour	$830,620	5,933	$140
Total Plan Recoveries	**$3,392,620**		

The proposed fees are in the same range as compared to other gas and electric utilities in and outside the Province, as shown in Table F-6 below.

Table F-6: The Planned Reconnection/Reactivation Fee is Comparable to Other Utilities

	Regular hour	**After hour**
FortisBC (Gas) Current Fee	$65	$105
FortisBC (Gas) **Proposed Fee**	$100	$140
Gaz Metro	$225 or $310 (depends on the annual load)	Not Specified.
Enbridge Gas	$68.25 disconnection fee $200 reconnection fee	Not specified
Union Gas	For non-payment: $65	Not specified.
Centra Gas Manitoba Inc.	$50	$65
SaskEnergy	$68 or $100 (depends on the annual load)	$95 or $135 (depends on the annual load)
AltaGas	Residential: $50	Not specified
Atco Gas	$90	$205
BC Hydro**	$125	$158
FortisBC** (Electric)	$100	$132

** Although BC Hydro and FortisBC (Electric) are not gas utilities, they are listed for comparative purposes as labour rates are similar provincially. . The average reactivation fee for the two major electric utilities in the province is $112 and $145 for regular hour and after hour calls respectively. Unlike FortisBC (Gas), these companies do not enter the premise to reactivate appliances.

The Companies are proposing to increase the reconnection/reactivation fee to $100 (regular hours) and $140 (after hours). The proposed change reasonably reflects the cost of providing service. If the current reconnection/reactivation fee continues through 2012-2013, all ratepayers will be subsidizing the lock-off and reconnection/reactivation costs of customers who have not paid their bills and who have been disconnected. Therefore, the proposed fee change mitigates negative impacts to other ratepayers and reduces the O&M cost per customer for all customers.

Appendix F-2

BILL IMPACT AND TARIFF CONTINUITIES

DRAFT BILL IMPACT SCHEDULES AND TARIFF CONTINUITIES

This appendix includes draft bill impact schedules and tariff continuities that result from the financial schedules contained in Section 7 of this Application and the corresponding rate proposals contained in Section 3 of this Application.

This appendix includes fourteen tabs as follows:

Utility/Region		Appendix F-2 Tabs	Application Reference
Mainland	January 1, 2012 January 1, 2013	1.1.1 / 1.1.2 1.2.1 / 1.2.2	Section 7, Tab 7.1
Vancouver Island	January 1, 2012 January 1, 2013	2.1,1 / 2.1.2 2.2.1 / 2.2.2	Section 7, Tab 7.2
Whistler	January 1, 2012 January 1, 2013	3.1 3.2	Section 7, Tab 7.3
Fort Nelson	January 1, 2012 January 1, 2013	4.1.1 / 4.1.2 4.2.1 / 4.2.2	Section 7, Tab 7.4

	RATE SCHEDULE 1: RESIDENTIAL SERVICE	**EXISTING JANUARY 1, 2011 RATES**			**DELIVERY MARGIN RELATED CHARGES CHANGES**			**PROPOSED JANUARY 1, 2012 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.275	$3.275	$3.275	$0.256	$0.256	$0.256	$3.531	$3.531	$3.531
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.207**	**$3.207**	**$3.207**	**$0.292**	**$0.292**	**$0.292**	**$3.499**	**$3.499**	**$3.499**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.009	$0.009	$0.009	($0.009)	($0.009)	($0.009)	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.349**	**$1.324**	**$1.364**	**($0.009)**	**($0.009)**	**($0.009)**	**$1.340**	**$1.315**	**$1.355**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.714	$2.714	$2.714	$0.193	$0.193	$0.193	$2.907	$2.907	$2.907
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.036)	($0.036)	($0.036)	$0.036	$0.036	$0.036	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.658**	**$2.658**	**$2.658**	**$0.217**	**$0.217**	**$0.217**	**$2.875**	**$2.875**	**$2.875**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.270**	**$2.270**	**$2.270**	**$0.165**	**$0.165**	**$0.165**	**$2.435**	**$2.435**	**$2.435**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.854	$0.854	$0.854	$0.081	$0.081	$0.081	$0.935	$0.935	$0.935
6	(b) Extension Period	$1.631	$1.631	$1.631	$0.081	$0.081	$0.081	$1.712	$1.712	$1.712
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.014)	($0.014)	($0.014)	$0.014	$0.014	$0.014	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.172	$6.157	$6.193	$0.095	$0.095	$0.095	$6.267	$6.252	$6.288
33	(b) Extension Period	$6.949	$6.934	$6.970	$0.095	$0.095	$0.095	$7.044	$7.029	$7.065

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
5										
6	**Delivery Charge per GJ**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$5.956	$5.941	$5.977	$0.072	$0.072	$0.072	$6.028	$6.013	$6.049

Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**EXISTING JANUARY 1, 2011 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.530	$8.523	$8.523	$0.252	$0.252	$0.252	$8.782	$8.775	$8.775

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JANUARY 1, 2011 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.608	$0.213	$3.821
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	($0.039)	$0.039	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$13.770	$0.252	$14.022

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.392	$6.377	$6.413	$0.080	$0.080	$0.080	$6.472	$6.457	$6.493

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.790	$0.790	$0.790	$0.048	$0.048	$0.048	$0.838	$0.838	$0.838
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	($0.009)	($0.009)	($0.009)	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.781	$0.781	$0.781	$0.057	$0.057	$0.057	$0.838	$0.838	$0.838

Line No.	**RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE** Particulars	**EFFECTIVE JANUARY 1, 2011**	**DELIVERY MARGIN RELATED CHARGES CHANGES**	**PROPOSED JANUARY 1, 2012 RATES**
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$12.673	$0.734	$13.407
7	(b) Firm MTQ	$0.088	$0.005	$0.093
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.003	$0.058	$1.061
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	($0.009)	$0.009	$0.000
13				
14		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
15	**Charges per gigajoule for UOR Gas**			
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.079	$0.014	$0.093
35	(b) Interruptible MTQ	$0.994	$0.067	$1.061

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Columbia Except Elkview	 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	 Elkview Coal	PROPOSED JANUARY 1, 2012 RATES Columbia Except Elkview	 Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.048	$1.827	$0.530	$0.120	$8.578	$1.947
7	(b) Firm MTQ	$0.086	$0.086	$0.006	$0.006	$0.092	$0.092
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.802	$0.201	$0.053	$0.013	$0.855	$0.214
11	(b) between and including Nov. 1 and Mar.31	$1.155	$0.287	$0.076	$0.019	$1.231	$0.306
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	($0.006)	($0.002)	$0.006	$0.002	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.080	$0.084	$0.012	$0.008	$0.092	$0.092
31	(b) Interruptible MTQ - Summer	$0.796	$0.199	$0.059	$0.015	$0.855	$0.214
32	- Winter	$1.149	$0.285	$0.082	$0.021	$1.231	$0.306

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EFFECTIVE JANUARY 1, 2011			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.270	$2.270	$2.270	$0.165	$0.165	$0.165	$2.435	$2.435	$2.435

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.624	$0.624	$0.624	$0.072	$0.072	$0.072	$0.696	$0.696	$0.696

Line No.	RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.609	$3.609	$3.609	$0.252	$0.252	$0.252	$3.861	$3.861	$3.861

Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**EFFECTIVE JANUARY 1, 2011** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.060	$1.060	$1.060	$0.080	$0.080	$0.080	$1.140	$1.140	$1.140

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume	Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge	365.25 days x	$0.389 =	$142.08	365.25 days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
4										
5	Delivery Charge	95.0 GJ x	$3.275 =	$311.1250	95.0 GJ x	$3.531 =	$335.4450	$0.256	$24.3200	2.41%
6	Rider 2 2009 ROE Rate Rider	95.0 GJ x	$0.000 =	$0.0000	95.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0 GJ x	($0.048) =	($4.5600)	95.0 GJ x	$0.000 =	$0.0000	$0.048	$4.5600	0.45%
8	Rider 5 RSAM	95.0 GJ x	($0.020) =	($1.9000)	95.0 GJ x	($0.032) =	($3.0400)	($0.012)	($1.1400)	-0.11%
9	Subtotal Delivery Margin Related Charges			**$446.75**			**$474.49**		**$27.74**	**2.75%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	95.0 GJ x	$1.340 =	$127.3000	95.0 GJ x	$1.340 =	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0 GJ x	$0.009 =	$0.8550	95.0 GJ x	$0.000 =	0.00	($0.009)	($0.8550)	-0.08%
14	Midstream Related Charges Subtotal			$128.16			$127.30		($0.86)	-0.09%
15										
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0 GJ x	$4.568 =	$433.96	95.0 GJ x	$4.568 =	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges			**$562.12**			**$561.26**		**($0.86)**	**-0.09%**
18										
19	Total *(with effective $/GJ rate)*	95.0	*$10.620*	**$1,008.87**	95.0	*$10.903*	**$1,035.75**	*$0.283*	**$26.88**	**2.66%**
20										
21	**INLAND SERVICE AREA**									
22	Delivery Margin Related Charges									
23	Basic Charge	365.25 days x	$0.389 =	$142.08	365.25 days	$0.389 =	$142.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	75.0 GJ x	$3.275 =	$245.6250	75.0 GJ x	$3.531 =	$264.8250	$0.256	$19.2000	2.33%
26	Rider 2 2009 ROE Rate Rider	75.0 GJ x	$0.000 =	$0.0000	75.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0 GJ x	($0.048) =	($3.6000)	75.0 GJ x	$0.000 =	$0.0000	$0.048	$3.6000	0.44%
28	Rider 5 RSAM	75.0 GJ x	($0.020) =	($1.5000)	75.0 GJ x	($0.032) =	($2.4000)	($0.012)	($0.9000)	-0.11%
29	Subtotal Delivery Margin Related Charges			**$382.61**			**$404.51**		**$21.90**	**2.66%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	75.0 GJ x	$1.315 =	$98.6250	75.0 GJ x	$1.315 =	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0 GJ x	$0.009 =	$0.6750	75.0 GJ x	$0.000 =	$0.0000	($0.009)	($0.6750)	-0.08%
34	Midstream Related Charges Subtotal			$99.30			$98.63		($0.67)	-0.08%
35										
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0 GJ x	$4.568 =	$342.60	75.0 GJ x	$4.568 =	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges			**$441.90**			**$441.23**		**($0.67)**	**-0.08%**
38										
39	Total *(with effective $/GJ rate)*	75.0	*$10.993*	**$824.51**	75.0	*$11.277*	**$845.74**	*$0.283*	**$21.23**	**2.57%**
40										
41	**COLUMBIA SERVICE AREA**									
42	Delivery Margin Related Charges									
43	Basic Charge	365.25 days x	$0.389 =	$142.08	365.25 days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
44										
45	Delivery Charge	80.0 GJ x	$3.275 =	$262.0000	80.0 GJ x	$3.531 =	$282.4800	$0.256	$20.4800	2.35%
46	Rider 2 2009 ROE Rate Rider	80.0 GJ x	$0.000 =	$0.0000	80.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0 GJ x	($0.048) =	($3.8400)	80.0 GJ x	$0.000 =	$0.0000	$0.048	$3.8400	0.44%
48	Rider 5 RSAM	80.0 GJ x	($0.020) =	($1.6000)	80.0 GJ x	($0.032) =	($2.5600)	($0.012)	($0.9600)	-0.11%
49	Subtotal Delivery Margin Related Charges			**$398.64**			**$422.00**		**$23.36**	**2.68%**
50										
51	Commodity Related Charges									
52	Midstream Cost Recovery Charge	80.0 GJ x	$1.355 =	$108.4000	80.0 GJ x	$1.355 =	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0 GJ x	$0.009 =	$0.7200	80.0 GJ x	$0.000 =	$0.0000	($0.009)	($0.7200)	-0.08%
54	Midstream Related Charges Subtotal			$109.12			$108.40		($0.72)	-0.08%
55										
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0 GJ x	$4.568	$365.44	80.0 GJ x	$4.568 =	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges			**$474.56**	80.0		**$473.84**		**($0.72)**	**-0.08%**
58										
59	Total *(with effective $/GJ rate)*	80.0	*$10.915*	**$873.20**	80.0	*$11.198*	**$895.84**	*$0.283*	**$22.64**	**2.59%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	300.0	GJ x	$2.714 =	$814.2000	300.0	GJ x	$2.907 =	$872.1000	$0.193	$57.9000	2.02%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	($0.036) =	($10.8000)	300.0	GJ x	$0.000 =	$0.0000	$0.036	$10.8000	0.38%
8	Rider 5 RSAM	300.0	GJ x	($0.020) =	($6.0000)	300.0	GJ x	($0.032) =	($9.6000)	($0.012)	($3.6000)	-0.13%
9	Subtotal Delivery Margin Related Charges				**$1,095.48**				**$1,160.58**		**$65.10**	**2.27%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327 =	$398.1000	300.0	GJ x	$1.327 =	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$398.10				$398.10		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568 =	$1,370.40	300.0	GJ x	$4.568 =	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$1,768.50**				**$1,768.50**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	300.0		*$9.547*	**$2,863.98**	300.0		*$9.764*	**$2,929.08**	*$0.217*	**$65.10**	**2.27%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	250.0	GJ x	$2.714 =	$678.5000	250.0	GJ x	$2.907 =	$726.7500	$0.193	$48.2500	1.99%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	($0.036) =	($9.0000)	250.0	GJ x	$0.000 =	$0.0000	$0.036	$9.0000	0.37%
28	Rider 5 RSAM	250.0	GJ x	($0.020) =	($5.0000)	250.0	GJ x	($0.032) =	($8.0000)	($0.012)	($3.0000)	-0.12%
29	Subtotal Delivery Margin Related Charges				**$962.58**				**$1,016.83**		**$54.25**	**2.23%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301 =	$325.2500	250.0	GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$325.25				$325.25		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568 =	$1,142.00	250.0	GJ x	$4.568 =	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$1,467.25**				**$1,467.25**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	250.0		*$9.719*	**$2,429.83**	250.0		*$9.936*	**$2,484.08**	*$0.217*	**$54.25**	**2.23%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	320.0	GJ x	$2.714 =	$868.4800	320.0	GJ x	$2.907 =	$930.2400	$0.193	$61.7600	2.03%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	($0.036) =	($11.5200)	320.0	GJ x	$0.000 =	$0.0000	$0.036	$11.5200	0.38%
48	Rider 5 RSAM	320.0	GJ x	($0.020) =	($6.4000)	320.0	GJ x	($0.032) =	($10.2400)	($0.012)	($3.8400)	-0.13%
49	Subtotal Delivery Margin Related Charges				**$1,148.64**				**$1,218.08**		**$69.44**	**2.28%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342 =	$429.4400	320.0	GJ x	$1.342 =	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$429.44				$429.44		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568 =	$1,461.76	320.0	GJ x	$4.568 =	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$1,891.20**				**$1,891.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	320.0		*$9.500*	**$3,039.84**	320.0		*$9.717*	**$3,109.28**	*$0.217*	**$69.44**	**2.28%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
4														
5	Delivery Charge	2,800.0	GJ x	$2.318	=	$6,490.4000	2,800.0	GJ x	$2.467	=	$6,907.6000	$0.149	$417.2000	1.77%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	($0.028)	=	($78.4000)	2,800.0	GJ x	$0.000	=	$0.0000	$0.028	$78.4000	0.33%
8	Rider 5 RSAM	2,800.0	GJ x	($0.020)	=	($56.0000)	2,800.0	GJ x	($0.032)	=	($89.6000)	($0.012)	($33.6000)	-0.14%
9	Subtotal Delivery Margin Related Charges					**$7,946.24**					**$8,408.24**		**$462.00**	**1.96%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018	=	$2,850.4000	2,800.0	GJ x	$1.018	=	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal					$2,850.40					$2,850.40		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568	=	$12,790.40	2,800.0	GJ x	$4.568	=	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$15,640.80**					**$15,640.80**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.424*		**$23,587.04**	2,800.0		*$8.589*		**$24,049.04**	*$0.165*	**$462.00**	**1.96%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
24														
25	Delivery Charge	2,600.0	GJ x	$2.318	=	$6,026.8000	2,600.0	GJ x	$2.467	=	$6,414.2000	$0.149	$387.4000	1.76%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	($0.028)	=	($72.8000)	2,600.0	GJ x	$0.000	=	$0.0000	$0.028	$72.8000	0.33%
28	Rider 5 RSAM	2,600.0	GJ x	($0.020)	=	($52.0000)	2,600.0	GJ x	($0.032)	=	($83.2000)	($0.012)	($31.2000)	-0.14%
29	Subtotal Delivery Margin Related Charges					**$7,492.24**					**$7,921.24**		**$429.00**	**1.95%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999	=	$2,597.4000	2,600.0	GJ x	$0.999	=	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal					$2,597.40					$2,597.40		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568	=	$11,876.80	2,600.0	GJ x	$4.568	=	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$14,474.20**					**$14,474.20**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.449*		**$21,966.44**	2,600.0		*$8.614*		**$22,395.44**	*$0.165*	**$429.00**	**1.95%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
44														
45	Delivery Charge	3,300.0	GJ x	$2.318	=	$7,649.4000	3,300.0	GJ x	$2.467	=	$8,141.1000	$0.149	$491.7000	1.78%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	($0.028)	=	($92.4000)	3,300.0	GJ x	$0.000	=	$0.0000	$0.028	$92.4000	0.34%
48	Rider 5 RSAM	3,300.0	GJ x	($0.020)	=	($66.0000)	3,300.0	GJ x	($0.032)	=	($105.6000)	($0.012)	($39.6000)	-0.14%
49	Subtotal Delivery Margin Related Charges					**$9,081.24**					**$9,625.74**		**$544.50**	**1.97%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036	=	$3,418.8000	3,300.0	GJ x	$1.036	=	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal					$3,418.80					$3,418.80		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568	=	$15,074.40	3,300.0	GJ x	$4.568	=	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$18,493.20**					**$18,493.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.356*		**$27,574.44**	3,300.0		*$8.521*		**$28,118.94**	*$0.165*	**$544.50**	**1.97%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
5												
6	Delivery Charge											
7	(a) Off-Peak Period	5,400.0	GJ x	$0.854 =	$4,611.6000	5,400.0	GJ x	$0.935 =	$5,049.0000	$0.081	$437.4000	1.20%
8	(b) Extension Period	0.0	GJ x	$1.631 =	$0.0000	0.0	GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0	GJ x	$0.000 =	$0.0000	5,400.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0	GJ x	($0.014) =	($75.6000)	5,400.0	GJ x	$0.000 =	$0.0000	$0.014	$75.6000	0.21%
11	Subtotal Delivery Margin Related Charges				**$7,622.52**				**$8,135.52**		**$513.00**	**1.41%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge											
15	(a) Off-Peak Period	5,400.0	GJ x	$0.764 =	$4,125.6000	5,400.0	GJ x	$0.764 =	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.764 =	$0.0000	0.0	GJ x	$0.764 =	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge											
18	(a) Off-Peak Period	5,400.0	GJ x	$4.568 =	24,667.2000	5,400.0	GJ x	$4.568 =	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
20												
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$28,792.80**				**$28,792.80**		**$0.00**	**0.00%**
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24												
25	Total during Off-Peak Period	5,400.0			**$36,415.32**	5,400.0			**$36,928.32**		**$513.00**	**1.41%**
26												
27												
28	**INLAND SERVICE AREA**											
29	Delivery Margin Related Charges											
30	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
31												
32	Delivery Charge											
33	(a) Off-Peak Period	9,300.0	GJ x	$0.854 =	$7,942.2000	9,300.0	GJ x	$0.935 =	$8,695.5000	$0.081	$753.3000	1.25%
34	(b) Extension Period	0.0	GJ x	$1.631 =	$0.0000	0.0	GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0	GJ x	$0.000 =	$0.0000	9,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0	GJ x	($0.014) =	($130.2000)	9,300.0	GJ x	$0.000 =	$0.0000	$0.014	$130.2000	0.22%
37	Subtotal Delivery Margin Related Charges				**$10,898.52**				**$11,782.02**		**$883.50**	**1.46%**
38												
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge											
41	(a) Off-Peak Period	9,300.0	GJ x	$0.749 =	$6,965.7000	9,300.0	GJ x	$0.749 =	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.749 =	$0.0000	0.0	GJ x	$0.749 =	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge											
44	(a) Off-Peak Period	9,300.0	GJ x	$4.568 =	$42,482.4000	9,300.0	GJ x	$4.568 =	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
46												
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$49,448.10**				**$49,448.10**		**$0.00**	**0.00%**
48												
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
51	Total during Off-Peak Period	9,300.0			**$60,346.62**	9,300.0			**$61,230.12**		**$883.50**	**1.46%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1												
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$15.943	**$11,191.99**	58.5	GJ x	$16.996	**$11,931.19**	$1.053	**$739.20**	**0.97%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.645	$6,256.5000	9,700.0	GJ x	$0.696	$6,751.2000	$0.051	$494.7000	0.65%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000	$0.0000	9,700.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	($0.021)	($203.7000)	9,700.0	GJ x	$0.000	$0.0000	$0.021	$203.7000	0.27%
11	Subtotal Delivery Margin Related Charges				**$6,052.80**				**$6,751.20**		**$698.40**	**0.92%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764	$7,410.8000	9,700.0	GJ x	$0.764	$7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568	$44,309.6000	9,700.0	GJ x	$4.568	$44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$51,720.40**				**$51,720.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.836*	**$76,009.19**	9,700.0		*$7.984*	**$77,446.79**	*$0.148*	**$1,437.60**	**1.89%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$15.943	**$15,687.91**	82.0	GJ x	$16.996	**$16,724.06**	$1.053	**$1,036.15**	**1.05%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.645	$8,256.0000	12,800.0	GJ x	$0.696	$8,908.8000	$0.051	$652.8000	0.66%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000	$0.0000	12,800.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	($0.021)	($268.8000)	12,800.0	GJ x	$0.000	$0.0000	$0.021	$268.8000	0.27%
29	Subtotal Delivery Margin Related Charges				**$7,987.20**				**$8,908.80**		**$921.60**	**0.93%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749	$9,587.2000	12,800.0	GJ x	$0.749	$9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568	$58,470.4000	12,800.0	GJ x	$4.568	$58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$68,057.60**				**$68,057.60**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.717*	**$98,776.71**	12,800.0		*$7.870*	**$100,734.46**	*$0.153*	**$1,957.75**	**1.98%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$15.943	**$10,598.91**	55.4	GJ x	$16.996	**$11,298.94**	$1.053	**$700.03**	**0.97%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.645	$5,869.5000	9,100.0	GJ x	$0.696	$6,333.6000	$0.051	$464.1000	0.64%
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000	$0.0000	9,100.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	($0.021)	($191.1000)	9,100.0	GJ x	$0.000	$0.0000	$0.021	$191.1000	0.27%
47	Subtotal Delivery Margin Related Charges				**$5,678.40**				**$6,333.60**		**$655.20**	**0.91%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785	$7,143.5000	9,100.0	GJ x	$0.785	$7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568	$41,568.8000	9,100.0	GJ x	$4.568	$41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,712.30**				**$48,712.30**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$7.916	**$72,033.61**	9,100.0		$8.065	**$73,388.84**	*$0.149*	**$1,355.23**	**1.88%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate		Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
5														
6	Delivery Charge	2,900.0	GJ x	$3.648	=	$10,579.2000	2,900.0	GJ x	$3.861	=	$11,196.9000	$0.213	$617.7000	2.43%
7	Rider 2 2009 ROE Rate Rider	2,900.0	GJ x	$0.000	=	$0.0000	2,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0	GJ x	($0.039)	=	($113.1000)	2,900.0	GJ x	$0.000	=	$0.0000	$0.039	$113.1000	0.44%
9	Subtotal Delivery Margin Related Charges					**$11,198.10**					**$11,928.90**		**$730.80**	**2.87%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.353	=	$1,023.7000	2,900.0	GJ x	$0.353	=	$1,023.7000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$4.568	=	$13,247.2000	2,900.0	GJ x	$4.568	=	$13,247.2000	$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$14,270.90**					**$14,270.90**		**$0.00**	**0.00%**
15														
16	Total *(with effective $/GJ rate)*	2,900.0		*$8.782*		**$25,469.00**	2,900.0		*$9.034*		**$26,199.80**	*$0.252*	**$730.80**	**2.87%**
17														
18														
19	**INLAND SERVICE AREA**													
20	Delivery Margin Related Charges													
21	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
22														
23	Delivery Charge	11,900.0	GJ x	$3.648	=	$43,411.2000	11,900.0	GJ x	$3.861	=	$45,945.9000	$0.213	$2,534.7000	2.48%
24	Rider 2 2009 ROE Rate Rider	11,900.0	GJ x	$0.000	=	$0.0000	11,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0	GJ x	($0.039)	=	($464.1000)	11,900.0	GJ x	$0.000	=	$0.0000	$0.039	$464.1000	0.45%
26	Subtotal Delivery Margin Related Charges					**$43,679.10**					**$46,677.90**		**$2,998.80**	**2.94%**
27														
28	Commodity Related Charges													
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.346	=	$4,117.4000	11,900.0	GJ x	$0.346	=	$4,117.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$4.568	=	$54,359.2000	11,900.0	GJ x	$4.568	=	$54,359.2000	$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$58,476.60**					**$58,476.60**		**$0.00**	**0.00%**
32														
33	Total *(with effective $/GJ rate)*	11,900.0		*$8.585*		**$102,155.70**	11,900.0		*$8.837*		**$105,154.50**	*$0.252*	**$2,998.80**	**2.94%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$1.073 =	$8,691.3000	8,100.0 GJ x	$1.140 =	$9,234.0000	$0.067	$542.7000	0.87%
7	Rider 2 2009 ROE Rate Rider	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0 GJ x	($0.013) =	($105.3000)	8,100.0 GJ x	$0.000 =	$0.0000	$0.013	$105.3000	0.17%
9	Rider 4 Reserve for Future Use	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges			**$8,586.00**			**$9,234.00**		**$648.00**	**1.04%**
11										
12	Commodity Related Charges									
13	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.764 =	$6,188.4000	8,100.0 GJ x	$0.764 =	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0 GJ x	$4.568 =	$37,000.8000	8,100.0 GJ x	$4.568 =	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$43,189.20**			**$43,189.20**		**$0.00**	**0.00%**
16										
17	Non-Standard Charges (not forecast)									
18	Index Pricing Option, UOR									
19										
20	Total *(with effective $/GJ rate)*	8,100.0	*$7.696*	**$62,335.20**	8,100.0	*$7.776*	**$62,983.20**	*$0.080*	**$648.00**	**1.04%**
21										
22										
23	**INLAND SERVICE AREA**									
24	Delivery Margin Related Charges									
25	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26										
27	Delivery Charge	4,000.0 GJ x	$1.073 =	$4,292.0000	4,000.0 GJ x	$1.140 =	$4,560.0000	$0.067	$268.0000	0.74%
28	Rider 2 2009 ROE Rate Rider	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0 GJ x	($0.013) =	($52.0000)	4,000.0 GJ x	$0.000 =	$0.0000	$0.013	$52.0000	0.14%
30	Rider 4 Reserve for Future Use	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges			**$4,240.00**			**$4,560.00**		**$320.00**	**0.89%**
32										
33	Commodity Related Charges									
34	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.749 =	$2,996.0000	4,000.0 GJ x	$0.749 =	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0 GJ x	$4.568 =	$18,272.0000	4,000.0 GJ x	$4.568 =	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$21,268.00**			**$21,268.00**		**$0.00**	**0.00%**
37										
38	Non-Standard Charges (not forecast)									
39	Index Pricing Option, UOR									
40										
41	Total *(with effective $/GJ rate)*	4,000.0	*$9.017*	**$36,068.00**	4,000.0	*$9.097*	**$36,388.00**	*$0.080*	**$320.00**	**0.89%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11

RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$3,664.00 =	**$43,968.00**	12 months x	$3,664.00 =	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4										
5										
6	Delivery Charge - Interruptible MTQ	467,305.6 GJ x	$0.790 =	$369,171.4240	467,305.6 GJ x	$0.838 =	$391,602.0928	$0.048	$22,430.6688	5.47%
7	Rider 2 2009 ROE Rate Rider	467,305.6 GJ x	$0.000 =	$0.0000	467,305.6 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6 GJ x	($0.009) =	($4,205.7504)	467,305.6 GJ x	$0.000 =	$0.0000	$0.009	$4,205.7504	1.03%
9	Transportation - Interruptible			**$364,965.67**			**$391,602.09**		**$26,636.42**	**6.50%**
10										
11										
12	Non-Standard Charges (not forecast)									
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas									
14										
15										
16	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
17										
18										
19	Total *(with effective $/GJ rate)*	467,305.6	*$0.877*	**$409,869.67**	467,305.6	*$0.934*	**$436,506.09**	*$0.057*	**$26,636.42**	**6.50%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**INLAND SERVICE AREA**													
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**	12	months x	$4,810.00	=	**$57,720.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$12.673	=	**$394,698.00**	2,595.4	GJ x	$13.407	=	**$417,558.36**	$0.734	**$22,860.36**	**4.33%**
7														
8														
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.088	=	$51,433.8704	584,475.8	GJ x	$0.093	=	$54,356.2494	$0.005	$2,922.3790	0.55%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	($0.009)	=	($5,260.2822)	584,475.8	GJ x	$0.000	=	$0.0000	$0.009	$5,260.2822	1.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$46,173.59**					**$54,356.25**		**$8,182.66**	**1.55%**
13														
14														
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.003	=	$28,693.7237	28,607.9	GJ x	$1.061	=	$30,352.9819	$0.058	$1,659.2582	0.31%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	($0.009)	=	($257.4711)	28,607.9	GJ x	$0.000	=	$0.0000	$0.009	$257.4711	0.05%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$28,436.25**					**$30,352.98**		**$1,916.73**	**0.36%**
19														
20														
21	Non-Standard Charges (not forecast)													
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
23														
24														
25	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
26														
27														
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.903*		**$527,963.84**	584,475.8		*$0.960*		**$560,923.59**	*$0.057*	**$32,959.75**	**6.24%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11

RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**													
3	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
4														
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.048	=	**$213,606.84**	2,211.8	GJ x	$8.578	=	**$227,673.84**	$0.530	**$14,067.00**	**4.52%**
6														
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.086	=	$39,331.7388	457,345.8	GJ x	$0.092	=	$42,075.8136	$0.006	$2,744.0748	0.88%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	=	$0.0000	457,345.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	($0.006)	=	($2,744.0748)	457,345.8	GJ x	$0.000	=	$0.0000	$0.006	$2,744.0748	0.88%
10	Transportation - Firm (Delivery Charge Firm MTQ)					**$36,587.66**					**$42,075.81**		**$5,488.15**	**1.77%**
11														
12	Delivery Charge - Interruptible MTQ													
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.802	=	$5,399.3848	6,732.4	GJ x	$0.855	=	$5,756.2020	$0.053	$356.8172	0.11%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.155	=	$0.0000	0.0	GJ x	$1.231	=	$0.0000	$0.076	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	=	$0.0000	6,732.4	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	($0.006)	=	($40.3944)	6,732.4	GJ x	$0.000	=	$0.0000	$0.006	$40.3944	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$5,358.99**					**$5,756.20**		**$397.21**	**0.13%**
18														
19	Non-Standard Charges (not forecast)													
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
21														
22	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
23														
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.670*		**$310,933.49**	464,078.2		*$0.713*		**$330,885.85**	*$0.043*	**$19,952.36**	**6.42%**
25														
26														
27	**COLUMBIA SERVICE - ELKVIEW COAL**													
28	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
29														
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.827	=	**$58,537.08**	2,670.0	GJ x	$1.947	=	**$62,381.88**	$0.120	**$3,844.80**	**2.25%**
31														
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.086	=	$54,313.6010	631,553.5	GJ x	$0.092	=	$58,102.9220	$0.006	$3,789.3210	2.21%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	=	$0.0000	631,553.5	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	($0.002)	=	($1,263.1070)	631,553.5	GJ x	$0.000	=	$0.0000	$0.002	$1,263.1070	0.74%
35	Transportation - Firm (Delivery Charge Firm MTQ)					**$53,050.49**					**$58,102.92**		**$5,052.43**	**2.95%**
36														
37	Delivery Charge - Interruptible MTQ													
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.201	=	$0.0000	0.0	GJ x	$0.214	=	$0.0000	$0.013	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.287	=	$4,162.3897	14,503.1	GJ x	$0.306	=	$4,437.9486	$0.019	$275.5589	0.16%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	($0.002)	=	($29.0062)	14,503.1	GJ x	$0.000	=	$0.0000	$0.002	$29.0062	0.02%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$4,133.38**					**$4,437.95**		**$304.57**	**0.18%**
44														
45	Non-Standard Charges (not forecast)													
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
47														
48	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
49														
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.265*		**$171,100.95**	646,056.6		*$0.279*		**$180,302.75**	*$0.014*	**$9,201.80**	**5.38%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1										
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	4,100.0 GJ x	$2.318 =	$9,503.8000	4,100.0 GJ x	$2.467 =	$10,114.7000	$0.149	$610.9000	5.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0 GJ x	$0.000 =	$0.0000	4,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0 GJ x	($0.028) =	($114.8000)	4,100.0 GJ x	$0.000 =	$0.0000	$0.028	$114.8000	0.97%
10	Rider 5 RSAM	4,100.0 GJ x	($0.020) =	($82.0000)	4,100.0 GJ x	($0.032) =	($131.2000)	($0.012)	($49.2000)	-0.42%
11	Transportation - Firm			**$9,307.00**			**$9,983.50**		**$676.50**	**5.72%**
12										
13	Non-Standard Charges (not forecast)									
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
15										
16	Total *(with effective $/GJ rate)*	4,100.0	*$2.886*	**$11,833.24**	4,100.0	*$3.051*	**$12,509.74**	*$0.165*	**$676.50**	**5.72%**
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	4,700.0 GJ x	$2.318 =	$10,894.6000	4,700.0 GJ x	$2.467 =	$11,594.9000	$0.149	$700.3000	5.31%
24	Rider 2 2009 ROE Rate Rider	4,700.0 GJ x	$0.000 =	$0.0000	4,700.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0 GJ x	($0.028) =	($131.6000)	4,700.0 GJ x	$0.000 =	$0.0000	$0.028	$131.6000	1.00%
26	Rider 5 RSAM	4,700.0 GJ x	($0.020) =	($94.0000)	4,700.0 GJ x	($0.032) =	($150.4000)	($0.012)	($56.4000)	-0.43%
27	Transportation - Firm			**$10,669.00**			**$11,444.50**		**$775.50**	**5.88%**
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
31										
32	Total *(with effective $/GJ rate)*	4,700.0	*$2.807*	**$13,195.24**	4,700.0	*$2.972*	**$13,970.74**	*$0.165*	**$775.50**	**5.88%**
33										
34	**COLUMBIA SERVICE AREA**									
35	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36										
37	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
38										
39	Delivery Charge	4,200.0 GJ x	$2.318 =	$9,735.6000	4,200.0 GJ x	$2.467 =	$10,361.4000	$0.149	$625.8000	5.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0 GJ x	$0.000 =	$0.0000	4,200.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0 GJ x	($0.028) =	($117.6000)	4,200.0 GJ x	$0.000 =	$0.0000	$0.028	$117.6000	0.98%
42	Rider 5 RSAM	4,200.0 GJ x	($0.020) =	($84.0000)	4,200.0 GJ x	($0.032) =	($134.4000)	($0.012)	($50.4000)	-0.42%
43	Transportation - Firm			**$9,534.00**			**$10,227.00**		**$693.00**	**5.75%**
44										
45	Non-Standard Charges (not forecast)									
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
47										
48	Total *(with effective $/GJ rate)*	4,200.0	*$2.871*	**$12,060.24**	4,200.0	*$3.036*	**$12,753.24**	*$0.165*	**$693.00**	**5.75%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Transportation - Firm Demand	97.2 GJ x	$15.943 =	**$18,595.92**	97.2 GJ x	$16.996 =	**$19,824.12**	$1.053	**$1,228.20**	**3.19%**
8										
9	Delivery Charge	19,086.2 GJ x	$0.645 =	$12,310.5990	19,086.2 GJ x	$0.696 =	$13,283.9952	$0.051	$973.3962	2.53%
10	Rider 2 2009 ROE Rate Rider	19,086.2 GJ x	$0.000 =	$0.0000	19,086.2 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2 GJ x	($0.021) =	($400.8102)	19,086.2 GJ x	$0.000 =	$0.0000	$0.021	$400.8102	1.04%
12	Transportation - Firm			**$11,909.79**			**$13,284.00**		**$1,374.21**	**3.57%**
13										
14	Non-Standard Charges (not forecast)									
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16										
17	Total *(with effective $/GJ rate)*	19,086.2	*$2.016*	**$38,485.71**	19,086.2	*$2.153*	**$41,088.12**	*$0.137*	**$2,602.41**	**6.76%**
18										
19	**INLAND SERVICE AREA**									
20	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
21										
22	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23										
24	Transportation - Firm Demand	212.6 GJ x	$15.943 =	**$40,673.76**	212.6 GJ x	$16.996 =	**$43,360.20**	$1.053	**$2,686.44**	**3.63%**
25										
26	Delivery Charge	40,670.5 GJ x	$0.645 =	$26,232.4725	40,670.5 GJ x	$0.696 =	$28,306.6680	$0.051	$2,074.1955	2.80%
27	Rider 2 2009 ROE Rate Rider	40,670.5 GJ x	$0.000 =	$0.0000	40,670.5 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5 GJ x	($0.021) =	($854.0805)	40,670.5 GJ x	$0.000 =	$0.0000	$0.021	$854.0805	1.15%
29	Transportation - Firm			**$25,378.39**			**$28,306.67**		**$2,928.28**	**3.96%**
30										
31	Non-Standard Charges (not forecast)									
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
33										
34	Total *(with effective $/GJ rate)*	40,670.5	*$1.820*	**$74,032.15**	40,670.5	*$1.958*	**$79,646.87**	*$0.138*	**$5,614.72**	**7.58%**
35										
36	**COLUMBIA SERVICE**									
37	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
38										
39	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
40										
41	Transportation - Firm Demand	182.2 GJ x	$15.943 =	**$34,857.72**	182.2 GJ x	$16.996 =	**$37,160.04**	$1.053	**$2,302.32**	**3.73%**
42										
43	Delivery Charge	30,357.8 GJ x	$0.645 =	$19,580.7810	30,357.8 GJ x	$0.696 =	$21,129.0288	$0.051	$1,548.2478	2.51%
44	Rider 2 2009 ROE Rate Rider	30,357.8 GJ x	$0.000 =	$0.0000	30,357.8 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8 GJ x	($0.021) =	($637.5138)	30,357.8 GJ x	$0.000 =	$0.0000	$0.021	$637.5138	1.03%
46	Transportation - Firm			**$18,943.27**			**$21,129.03**		**$2,185.76**	**3.54%**
47										
48	Non-Standard Charges (not forecast)									
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
50										
51	Total *(with effective $/GJ rate)*	30,357.8	*$2.035*	**$61,780.99**	30,357.8	*$2.183*	**$66,269.07**	*$0.148*	**$4,488.08**	**7.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
4														
5	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
6														
7	Delivery Charge	53,957.0	GJ x	$1.073	=	$57,895.8610	53,957.0	GJ x	$1.140	=	$61,510.9800	$0.067	$3,615.1190	5.26%
8	Rider 2 2009 ROE Rate Rider	53,957.0	GJ x	$0.000	=	$0.0000	53,957.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0	GJ x	($0.013)	=	($701.4410)	53,957.0	GJ x	$0.000	=	$0.0000	$0.013	$701.4410	1.02%
10	Transportation - Interruptible					**$57,194.42**					**$61,510.98**		**$4,316.56**	**6.28%**
11														
12	Non-Standard Charges (not forecast)													
13	UOR, Balancing gas, Backstopping Gas													
14														
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.273*		**$68,690.42**	53,957.0		*$1.353*		**$73,006.98**	*$0.080*	**$4,316.56**	**6.28%**
16														
17														
18	**INLAND SERVICE AREA**													
19	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
20														
21	Administration Charge	12.0	months x	$78.00	=	**$936.00**	12.0	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
22														
23	Delivery Charge	48,903.9	GJ x	$1.073	=	$52,473.8847	48,903.9	GJ x	$1.140	=	$55,750.4460	$0.067	$3,276.5613	5.17%
24	Rider 2 2009 ROE Rate Rider	48,903.9	GJ x	$0.000	=	$0.0000	48,903.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9	GJ x	($0.013)	=	($635.7507)	48,903.9	GJ x	$0.000	=	$0.0000	$0.013	$635.7507	1.00%
26	Transportation - Interruptible					**$51,838.13**					**$55,750.45**		**$3,912.32**	**6.18%**
27														
28														
29	Non-Standard Charges (not forecast)													
30	UOR, Balancing gas, Backstopping Gas													
31		48,903.9		*$1.295*		**$63,334.13**	48,903.9		*$1.375*		**$67,246.45**	*$0.080*	**$3,912.32**	**6.18%**
32	Total *(with effective $/GJ rate)*													
33														
34														
35	**COLUMBIA SERVICE AREA**													
36	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
37														
38	Administration Charge	12.0	months x	$78.00	=	**$936.00**	12.0	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
39														
40	Delivery Charge	7,733.8	GJ x	$1.073	=	$8,298.3674	7,733.8	GJ x	$1.140	=	$8,816.5320	$0.067	$518.1646	0.82%
41	Rider 2 2009 ROE Rate Rider	7,733.8	GJ x	$0.000	=	$0.0000	7,733.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8	GJ x	($0.013)	=	($100.5394)	7,733.8	GJ x	$0.000	=	$0.0000	$0.013	$100.5394	0.16%
43	Transportation - Interruptible					**$8,197.83**					**$8,816.53**		**$618.70**	**0.98%**
44														
45														
46	Non-Standard Charges (not forecast)													
47	UOR, Balancing gas, Backstopping Gas													
48		7,733.8		*$2.546*		**$19,693.83**	7,733.8		*$2.626*		**$20,312.53**	*$0.080*	**$618.70**	**0.98%**
49	Total *(with effective $/GJ rate)*													

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
1	**INLAND SERVICE AREA**													
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$3.275	=	$163.7500	50.0	GJ x	$3.531	=	$176.5500	$0.256	$12.8000	1.20%
8	Rider 2 2009 ROE Rate Rider	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	($0.048)	=	($2.4000)	50.0	GJ x	$0.000	=	$0.0000	$0.048	$2.4000	0.23%
10	Rider 5 RSAM	50.0	GJ x	($0.020)	=	($1.0000)	50.0	GJ x	($0.032)	=	($1.6000)	($0.012)	($0.6000)	-0.06%
11	Subtotal Delivery Margin Related Charges			$3.207		**$302.43**			$3.499		**$317.03**		**$14.60**	**1.37%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$1.315	=	$65.7500	50.0	GJ x	$1.315	=	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$4.568	=	$228.4000	50.0	GJ x	$4.568	=	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$9.331	=	$466.5500	50.0	GJ x	$9.331	=	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges			$15.214		**$760.70**			$15.214		**$760.70**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$21.263*		**$1,063.13**	50.0		*$21.555*		**$1,077.73**	*$0.292*	**$14.60**	**1.37%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.714	=	$678.5000	250.0	GJ x	$2.907	=	$726.7500	$0.193	$48.2500	1.07%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	($0.036)	=	($9.0000)	250.0	GJ x	$0.000	=	$0.0000	$0.036	$9.0000	0.20%
28	Rider 5 RSAM	250.0	GJ x	($0.020)	=	($5.0000)	250.0	GJ x	($0.032)	=	($8.0000)	($0.012)	($3.0000)	-0.07%
29	Subtotal Delivery Margin Related Charges			$2.658		**$962.58**			$2.875		**$1,016.83**		**$54.25**	**1.21%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$4.568	=	$1,142.0000	250.0	GJ x	$4.568	=	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$8.254	=	$2,063.5000	250.0	GJ x	$8.254	=	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges			$14.123		**$3,530.75**			$14.123		**$3,530.75**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$17.973*		**$4,493.33**	250.0		*$18.190*		**$4,547.58**	*$0.217*	**$54.25**	**1.21%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.318	=	$10,431.0000	4,500.0	GJ x	$2.467	=	$11,101.5000	$0.149	$670.5000	0.89%
44	Rider 2 2009 ROE Rate Rider	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0	GJ x	($0.028)	=	($126.0000)	4,500.0	GJ x	$0.000	=	$0.0000	$0.028	$126.0000	0.17%
46	Rider 5 RSAM	4,500.0	GJ x	($0.020)	=	($90.0000)	4,500.0	GJ x	($0.032)	=	($144.0000)	($0.012)	($54.0000)	-0.07%
47	Subtotal Delivery Margin Related Charges			$2.270		**$11,805.24**			$2.435		**$12,547.74**		**$742.50**	**0.99%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.999	=	$4,495.5000	4,500.0	GJ x	$0.999	=	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$4.568	=	$20,556.0000	4,500.0	GJ x	$4.568	=	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$8.556	=	$38,502.0000	4,500.0	GJ x	$8.556	=	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges			$14.123		**$63,553.50**			$14.123		**$63,553.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$16.746*		**$75,358.74**	4,500.0		*$16.911*		**$76,101.24**	*$0.165*	**$742.50**	**0.99%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent comparison purposes.

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.531	$3.531	$3.531	$0.325	$0.325	$0.325	$3.856	$3.856	$3.856
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.499**	**$3.499**	**$3.499**	**$0.325**	**$0.325**	**$0.325**	**$3.824**	**$3.824**	**$3.824**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.340**	**$1.315**	**$1.355**	**$0.000**	**$0.000**	**$0.000**	**$1.340**	**$1.315**	**$1.355**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.907	$2.907	$2.907	$0.245	$0.245	$0.245	$3.152	$3.152	$3.152
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.875**	**$2.875**	**$2.875**	**$0.245**	**$0.245**	**$0.245**	**$3.120**	**$3.120**	**$3.120**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.435**	**$2.435**	**$2.435**	**$0.188**	**$0.188**	**$0.188**	**$2.623**	**$2.623**	**$2.623**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

FORTISBC ENERGY INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

APPENDIX F-2
TAB 1.2.1
PAGE 4
SCHEDULE 4

Line No.	**RATE SCHEDULE 4: SEASONAL SERVICE** Particulars	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.935	$0.935	$0.935	$0.103	$0.103	$0.103	$1.038	$1.038	$1.038
6	(b) Extension Period	$1.712	$1.712	$1.712	$0.103	$0.103	$0.103	$1.815	$1.815	$1.815
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.267	$6.252	$6.288	$0.103	$0.103	$0.103	$6.370	$6.355	$6.391
33	(b) Extension Period	$7.044	$7.029	$7.065	$0.103	$0.103	$0.103	$7.147	$7.132	$7.168

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
5										
6	**Delivery Charge per GJ**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$6.028	$6.013	$6.049	$0.065	$0.065	$0.065	$6.093	$6.078	$6.114

Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.782	$8.775	$8.775	$0.266	$0.266	$0.266	$9.048	$9.041	$9.041

Line No.	**RATE SCHEDULE 6A: NGV - VRA's** Particulars	**PROPOSED JANUARY 1, 2012 RATES**	**DELIVERY MARGIN RELATED CHARGES CHANGES**	**PROPOSED JANUARY 1, 2013 RATES**
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.821	$0.266	$4.087
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	$0.000	$0.000	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$14.022	$0.266	$14.288

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.472	$6.457	$6.493	$0.086	$0.086	$0.086	$6.558	$6.543	$6.579

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	PROPOSED JANUARY 1, 2012	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$13.407	$0.927	$14.334
7	(b) Firm MTQ	$0.093	$0.007	$0.100
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.061	$0.073	$1.134
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	$0.000	$0.000	$0.000
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.093	$0.007	$0.100
35	(b) Interruptible MTQ	$1.061	$0.073	$1.134

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Columbia Except Elkview	PROPOSED JANUARY 1, 2012 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	DELIVERY MARGIN RELATED CHARGES CHANGES Elkview Coal	PROPOSED JANUARY 1, 2013 RATES Columbia Except Elkview	PROPOSED JANUARY 1, 2013 RATES Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.578	$1.947	$0.667	$0.152	$9.245	$2.099
7	(b) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
11	(b) between and including Nov. 1 and Mar.31	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
31	(b) Interruptible MTQ - Summer	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
32	- Winter	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.435	$2.435	$2.435	$0.188	$0.188	$0.188	$2.623	$2.623	$2.623

Line No.	**RATE SCHEDULE 25** **GENERAL FIRM T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** **Lower Mainland**	**Inland**	**Columbia**	**DELIVERY MARGIN RELATED CHARGES CHANGES** **Lower Mainland**	**Inland**	**Columbia**	**PROPOSED JANUARY 1, 2013 RATES** **Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761

Line No.	**RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127

Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
4														
5	Delivery Charge	95.0	GJ x	$3.531	=	$335.4450	95.0	GJ x	$3.856	=	$366.3200	$0.325	$30.8750	2.98%
6	Rider 2 2009 ROE Rate Rider	95.0	GJ x	$0.000	=	$0.0000	95.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0	GJ x	$0.000	=	$0.0000	95.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	95.0	GJ x	($0.032)	=	($3.0400)	95.0	GJ x	($0.032)	=	($3.0400)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$474.49**					**$505.36**		**$30.87**	**2.98%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	95.0	GJ x	$1.340	=	$127.3000	95.0	GJ x	$1.340	=	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	$0.000	=	$0.0000	95.0	GJ x	$0.000	=	0.00	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal					$127.30					$127.30		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	$4.568	=	$433.96	95.0	GJ x	$4.568	=	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$561.26**					**$561.26**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	95.0		*$10.903*		**$1,035.75**	95.0		*$11.228*		**$1,066.62**	*$0.325*	**$30.87**	**2.98%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days	$0.389	=	$142.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	75.0	GJ x	$3.531	=	$264.8250	75.0	GJ x	$3.856	=	$289.2000	$0.325	$24.3750	2.88%
26	Rider 2 2009 ROE Rate Rider	75.0	GJ x	$0.000	=	$0.0000	75.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0	GJ x	$0.000	=	$0.0000	75.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	75.0	GJ x	($0.032)	=	($2.4000)	75.0	GJ x	($0.032)	=	($2.4000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges					**$404.51**					**$428.88**		**$24.37**	**2.88%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	75.0	GJ x	$1.315	=	$98.6250	75.0	GJ x	$1.315	=	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	$0.000	=	$0.0000	75.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal					$98.63					$98.63		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	$4.568	=	$342.60	75.0	GJ x	$4.568	=	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$441.23**					**$441.23**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	75.0		*$11.277*		**$845.74**	75.0		*$11.601*		**$870.11**	*$0.325*	**$24.37**	**2.88%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
44														
45	Delivery Charge	80.0	GJ x	$3.531	=	$282.4800	80.0	GJ x	$3.856	=	$308.4800	$0.325	$26.0000	2.90%
46	Rider 2 2009 ROE Rate Rider	80.0	GJ x	$0.000	=	$0.0000	80.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0	GJ x	$0.000	=	$0.0000	80.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	80.0	GJ x	($0.032)	=	($2.5600)	80.0	GJ x	($0.032)	=	($2.5600)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges					**$422.00**					**$448.00**		**$26.00**	**2.90%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	80.0	GJ x	$1.355	=	$108.4000	80.0	GJ x	$1.355	=	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0	GJ x	$0.000	=	$0.0000	80.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal					$108.40					$108.40		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	$4.568		$365.44	80.0	GJ x	$4.568	=	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$473.84**	80.0				**$473.84**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	80.0		*$11.198*		**$895.84**	80.0		*$11.523*		**$921.84**	*$0.325*	**$26.00**	**2.90%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	300.0	GJ x	$2.907 =	$872.1000	300.0	GJ x	$3.152 =	$945.6000	$0.245	$73.5000	2.51%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	300.0	GJ x	($0.032) =	($9.6000)	300.0	GJ x	($0.032) =	($9.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$1,160.58**				**$1,234.08**		**$73.50**	**2.51%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327 =	$398.1000	300.0	GJ x	$1.327 =	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$398.10				$398.10		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568 =	$1,370.40	300.0	GJ x	$4.568 =	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$1,768.50**				**$1,768.50**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	300.0		*$9.764*	**$2,929.08**	300.0		*$10.009*	**$3,002.58**	*$0.245*	**$73.50**	**2.51%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	250.0	GJ x	$2.907 =	$726.7500	250.0	GJ x	$3.152 =	$788.0000	$0.245	$61.2500	2.47%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032) =	($8.0000)	250.0	GJ x	($0.032) =	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$1,016.83**				**$1,078.08**		**$61.25**	**2.47%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301 =	$325.2500	250.0	GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$325.25				$325.25		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568 =	$1,142.00	250.0	GJ x	$4.568 =	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$1,467.25**				**$1,467.25**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	250.0		*$9.936*	**$2,484.08**	250.0		*$10.181*	**$2,545.33**	*$0.245*	**$61.25**	**2.47%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	320.0	GJ x	$2.907 =	$930.2400	320.0	GJ x	$3.152 =	$1,008.6400	$0.245	$78.4000	2.52%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	320.0	GJ x	($0.032) =	($10.2400)	320.0	GJ x	($0.032) =	($10.2400)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges				**$1,218.08**				**$1,296.48**		**$78.40**	**2.52%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342 =	$429.4400	320.0	GJ x	$1.342 =	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$429.44				$429.44		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568 =	$1,461.76	320.0	GJ x	$4.568 =	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$1,891.20**				**$1,891.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	320.0		*$9.717*	**$3,109.28**	320.0		*$9.962*	**$3,187.68**	*$0.245*	**$78.40**	**2.52%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
4												
5	Delivery Charge	2,800.0	GJ x	$2.467 =	$6,907.6000	2,800.0	GJ x	$2.655 =	$7,434.0000	$0.188	$526.4000	2.19%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	2,800.0	GJ x	($0.032) =	($89.6000)	2,800.0	GJ x	($0.032) =	($89.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$8,408.24**				**$8,934.64**		**$526.40**	**2.19%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018 =	$2,850.4000	2,800.0	GJ x	$1.018 =	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$2,850.40				$2,850.40		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568 =	$12,790.40	2,800.0	GJ x	$4.568 =	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$15,640.80**				**$15,640.80**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.589*	**$24,049.04**	2,800.0		*$8.777*	**$24,575.44**	*$0.188*	**$526.40**	**2.19%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
24												
25	Delivery Charge	2,600.0	GJ x	$2.467 =	$6,414.2000	2,600.0	GJ x	$2.655 =	$6,903.0000	$0.188	$488.8000	2.18%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	2,600.0	GJ x	($0.032) =	($83.2000)	2,600.0	GJ x	($0.032) =	($83.2000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$7,921.24**				**$8,410.04**		**$488.80**	**2.18%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999 =	$2,597.4000	2,600.0	GJ x	$0.999 =	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$2,597.40				$2,597.40		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568 =	$11,876.80	2,600.0	GJ x	$4.568 =	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$14,474.20**				**$14,474.20**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.614*	**$22,395.44**	2,600.0		*$8.802*	**$22,884.24**	*$0.188*	**$488.80**	**2.18%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
44												
45	Delivery Charge	3,300.0	GJ x	$2.467 =	$8,141.1000	3,300.0	GJ x	$2.655 =	$8,761.5000	$0.188	$620.4000	2.21%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	3,300.0	GJ x	($0.032) =	($105.6000)	3,300.0	GJ x	($0.032) =	($105.6000)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges				**$9,625.74**				**$10,246.14**		**$620.40**	**2.21%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036 =	$3,418.8000	3,300.0	GJ x	$1.036 =	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$3,418.80				$3,418.80		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568 =	$15,074.40	3,300.0	GJ x	$4.568 =	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$18,493.20**				**$18,493.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.521*	**$28,118.94**	3,300.0		*$8.709*	**$28,739.34**	*$0.188*	**$620.40**	**2.21%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	214	days x	$14.423	=	$3,086.5216	214	days x	$14.423	=	$3,086.5216	$0.00	$0.00	0.00%
5														
6	Delivery Charge													
7	(a) Off-Peak Period	5,400.0	GJ x	$0.935	=	$5,049.0000	5,400.0	GJ x	$1.038	=	$5,605.2000	$0.103	$556.2000	1.51%
8	(b) Extension Period	0.0	GJ x	$1.712	=	$0.0000	0.0	GJ x	$1.815	=	$0.0000	$0.103	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0	GJ x	$0.000	=	$0.0000	5,400.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0	GJ x	$0.000	=	$0.0000	5,400.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges					**$8,135.52**					**$8,691.72**		**$556.20**	**1.51%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge													
15	(a) Off-Peak Period	5,400.0	GJ x	$0.764	=	$4,125.6000	5,400.0	GJ x	$0.764	=	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.764	=	$0.0000	0.0	GJ x	$0.764	=	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge													
18	(a) Off-Peak Period	5,400.0	GJ x	$4.568	=	24,667.2000	5,400.0	GJ x	$4.568	=	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$4.568	=	$0.0000	0.0	GJ x	$4.568	=	$0.0000	$0.000	$0.0000	0.00%
20														
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak					**$28,792.80**					**$28,792.80**		**$0.00**	**0.00%**
22														
23	Unauthorized Gas Charge During Peak Period (not forecast)													
24														
25	Total during Off-Peak Period	5,400.0				**$36,928.32**	5,400.0				**$37,484.52**		**$556.20**	**1.51%**
26														
27														
28	**INLAND SERVICE AREA**													
29	Delivery Margin Related Charges													
30	Basic Charge	214	days x	$14.423	=	$3,086.5216	214	days x	$14.423	=	$3,086.5216	$0.00	$0.00	0.00%
31														
32	Delivery Charge													
33	(a) Off-Peak Period	9,300.0	GJ x	$0.935	=	$8,695.5000	9,300.0	GJ x	$1.038	=	$9,653.4000	$0.103	$957.9000	1.56%
34	(b) Extension Period	0.0	GJ x	$1.712	=	$0.0000	0.0	GJ x	$1.815	=	$0.0000	$0.103	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0	GJ x	$0.000	=	$0.0000	9,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0	GJ x	$0.000	=	$0.0000	9,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
37	Subtotal Delivery Margin Related Charges					**$11,782.02**					**$12,739.92**		**$957.90**	**1.56%**
38														
39	Commodity Related Charges													
40	Midstream Cost Recovery Charge													
41	(a) Off-Peak Period	9,300.0	GJ x	$0.749	=	$6,965.7000	9,300.0	GJ x	$0.749	=	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.749	=	$0.0000	0.0	GJ x	$0.749	=	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge													
44	(a) Off-Peak Period	9,300.0	GJ x	$4.568	=	$42,482.4000	9,300.0	GJ x	$4.568	=	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$4.568	=	$0.0000	0.0	GJ x	$4.568	=	$0.0000	$0.000	$0.0000	0.00%
46														
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak					**$49,448.10**					**$49,448.10**		**$0.00**	**0.00%**
48														
49	Unauthorized Gas Charge During Peak Period (not forecast)													
50														
51	Total during Off-Peak Period	9,300.0				**$61,230.12**	9,300.0				**$62,188.02**		**$957.90**	**1.56%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$16.996	= **$11,931.19**	58.5	GJ x	$18.324	= **$12,863.45**	$1.328	**$932.26**	**1.20%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.696	= $6,751.2000	9,700.0	GJ x	$0.761	= $7,381.7000	$0.065	$630.5000	0.81%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000	= $0.0000	9,700.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	$0.000	= $0.0000	9,700.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges				**$6,751.20**				**$7,381.70**		**$630.50**	**0.81%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764	= $7,410.8000	9,700.0	GJ x	$0.764	= $7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568	= $44,309.6000	9,700.0	GJ x	$4.568	= $44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$51,720.40**				**$51,720.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.984*	**$77,446.79**	9,700.0		*$8.145*	**$79,009.55**	*$0.161*	**$1,562.76**	**2.02%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$16.996	= **$16,724.06**	82.0	GJ x	$18.324	= **$18,030.82**	$1.328	**$1,306.76**	**1.30%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.696	= $8,908.8000	12,800.0	GJ x	$0.761	= $9,740.8000	$0.065	$832.0000	0.83%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000	= $0.0000	12,800.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	$0.000	= $0.0000	12,800.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$8,908.80**				**$9,740.80**		**$832.00**	**0.83%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749	= $9,587.2000	12,800.0	GJ x	$0.749	= $9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568	= $58,470.4000	12,800.0	GJ x	$4.568	= $58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$68,057.60**				**$68,057.60**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.870*	**$100,734.46**	12,800.0		*$8.037*	**$102,873.22**	*$0.167*	**$2,138.76**	**2.12%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$16.996	= **$11,298.94**	55.4	GJ x	$18.324	= **$12,181.80**	$1.328	**$882.86**	**1.20%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.696	= $6,333.6000	9,100.0	GJ x	$0.761	= $6,925.1000	$0.065	$591.5000	PAGE 13
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000	= $0.0000	9,100.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	$0.000	= $0.0000	9,100.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges				**$6,333.60**				**$6,925.10**		**$591.50**	**0.81%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785	= $7,143.5000	9,100.0	GJ x	$0.785	= $7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568	= $41,568.8000	9,100.0	GJ x	$4.568	= $41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,712.30**				**$48,712.30**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$8.065	**$73,388.84**	9,100.0		$8.227	**$74,863.20**	*$0.162*	**$1,474.36**	**2.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES Volume		Rate		Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
5														
6	Delivery Charge	2,900.0	GJ x	$3.861	=	$11,196.9000	2,900.0	GJ x	$4.127	=	$11,968.3000	$0.266	$771.4000	2.94%
7	Rider 2 2009 ROE Rate Rider	2,900.0	GJ x	$0.000	=	$0.0000	2,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0	GJ x	$0.000	=	$0.0000	2,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$11,928.90**					**$12,700.30**		**$771.40**	**2.94%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.353	=	$1,023.7000	2,900.0	GJ x	$0.353	=	$1,023.7000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$4.568	=	$13,247.2000	2,900.0	GJ x	$4.568	=	$13,247.2000	$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$14,270.90**					**$14,270.90**		**$0.00**	**0.00%**
15														
16	Total *(with effective $/GJ rate)*	2,900.0		*$9.034*		**$26,199.80**	2,900.0		*$9.300*		**$26,971.20**	*$0.266*	**$771.40**	**2.94%**
17														
18														
19	**INLAND SERVICE AREA**													
20	Delivery Margin Related Charges													
21	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
22														
23	Delivery Charge	11,900.0	GJ x	$3.861	=	$45,945.9000	11,900.0	GJ x	$4.127	=	$49,111.3000	$0.266	$3,165.4000	3.01%
24	Rider 2 2009 ROE Rate Rider	11,900.0	GJ x	$0.000	=	$0.0000	11,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0	GJ x	$0.000	=	$0.0000	11,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
26	Subtotal Delivery Margin Related Charges					**$46,677.90**					**$49,843.30**		**$3,165.40**	**3.01%**
27														
28	Commodity Related Charges													
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.346	=	$4,117.4000	11,900.0	GJ x	$0.346	=	$4,117.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$4.568	=	$54,359.2000	11,900.0	GJ x	$4.568	=	$54,359.2000	$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$58,476.60**					**$58,476.60**		**$0.00**	**0.00%**
32														
33	Total *(with effective $/GJ rate)*	11,900.0		*$8.837*		**$105,154.50**	11,900.0		*$9.103*		**$108,319.90**	*$0.266*	**$3,165.40**	**3.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$1.140 =	$9,234.0000	8,100.0 GJ x	$1.226 =	$9,930.6000	$0.086	$696.6000	1.11%
7	Rider 2 2009 ROE Rate Rider	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 4 Reserve for Future Use	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges			**$9,234.00**			**$9,930.60**		**$696.60**	**1.11%**
11										
12	Commodity Related Charges									
13	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.764 =	$6,188.4000	8,100.0 GJ x	$0.764 =	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0 GJ x	$4.568 =	$37,000.8000	8,100.0 GJ x	$4.568 =	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$43,189.20**			**$43,189.20**		**$0.00**	**0.00%**
16										
17	Non-Standard Charges (not forecast)									
18	Index Pricing Option, UOR									
19										
20	Total *(with effective $/GJ rate)*	8,100.0	*$7.776*	**$62,983.20**	8,100.0	*$7.862*	**$63,679.80**	*$0.086*	**$696.60**	**1.11%**
21										
22										
23	**INLAND SERVICE AREA**									
24	Delivery Margin Related Charges									
25	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26										
27	Delivery Charge	4,000.0 GJ x	$1.140 =	$4,560.0000	4,000.0 GJ x	$1.226 =	$4,904.0000	$0.086	$344.0000	0.95%
28	Rider 2 2009 ROE Rate Rider	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
30	Rider 4 Reserve for Future Use	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges			**$4,560.00**			**$4,904.00**		**$344.00**	**0.95%**
32										
33	Commodity Related Charges									
34	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.749 =	$2,996.0000	4,000.0 GJ x	$0.749 =	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0 GJ x	$4.568 =	$18,272.0000	4,000.0 GJ x	$4.568 =	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$21,268.00**			**$21,268.00**		**$0.00**	**0.00%**
37										
38	Non-Standard Charges (not forecast)									
39	Index Pricing Option, UOR									
40										
41	Total *(with effective $/GJ rate)*	4,000.0	*$9.097*	**$36,388.00**	4,000.0	*$9.183*	**$36,732.00**	*$0.086*	**$344.00**	**0.95%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012						PROPOSED JANUARY 1, 2013 RATES						Annual Increase/Decrease		
1		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**															
3	Basic Charge	12	months	x	$3,664.00	=	**$43,968.00**	12	months	x	$3,664.00	=	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4																
5																
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ	x	$0.838	=	$391,602.0928	467,305.6	GJ	x	$0.899	=	$420,107.7344	$0.061	$28,505.6416	6.53%
7	Rider 2 2009 ROE Rate Rider	467,305.6	GJ	x	$0.000	=	$0.0000	467,305.6	GJ	x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6	GJ	x	$0.000	=	$0.0000	467,305.6	GJ	x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Transportation - Interruptible						**$391,602.09**						**$420,107.73**		**$28,505.64**	**6.53%**
10																
11																
12	Non-Standard Charges (not forecast)															
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas															
14																
15																
16	Administration Charge	12	months	x	$78.00	=	**$936.00**	12	months	x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
17																
18																
19	Total *(with effective $/GJ rate)*	467,305.6			*$0.934*		**$436,506.09**	467,305.6			*$0.995*		**$465,011.73**	*$0.061*	**$28,505.64**	**6.53%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012						PROPOSED JANUARY 1, 2013 RATES						Annual Increase/Decrease		
1		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2	**INLAND SERVICE AREA**															
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**		12	months x	$4,810.00	=	**$57,720.00**		$0.00	**$0.00**	**0.00%**
4																
5																
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$13.407	=	**$417,558.36**		2,595.4	GJ x	$14.334	=	**$446,429.52**		$0.927	**$28,871.16**	**5.15%**
7																
8																
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.093	=	$54,356.2494		584,475.8	GJ x	$0.100	=	$58,447.5800		$0.007	$4,091.3306	0.73%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	=	$0.0000		584,475.8	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	$0.000	=	$0.0000		584,475.8	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$54,356.25**						**$58,447.58**			**$4,091.33**	**0.73%**
13																
14																
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.061	=	$30,352.9819		28,607.9	GJ x	$1.134	=	$32,441.3586		$0.073	$2,088.3767	0.37%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	=	$0.0000		28,607.9	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	$0.000	=	$0.0000		28,607.9	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$30,352.98**						**$32,441.36**			**$2,088.38**	**0.37%**
19																
20																
21	Non-Standard Charges (not forecast)															
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas															
23																
24																
25	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
26																
27																
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.960*		**$560,923.59**		584,475.8		*$1.020*		**$595,974.46**		*$0.060*	**$35,050.87**	**6.25%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**													
3	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
4														
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.578	=	**$227,673.84**	2,211.8	GJ x	$9.245	=	**$245,377.08**	$0.667	**$17,703.24**	**5.35%**
6														
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.092	=	$42,075.8136	457,345.8	GJ x	$0.099	=	$45,277.2342	$0.007	$3,201.4206	0.97%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	=	$0.0000	457,345.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	$0.000	=	$0.0000	457,345.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Transportation - Firm (Delivery Charge Firm MTQ)					**$42,075.81**					**$45,277.23**		**$3,201.42**	**0.97%**
11														
12	Delivery Charge - Interruptible MTQ													
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.855	=	$5,756.2020	6,732.4	GJ x	$0.921	=	$6,200.5404	$0.066	$444.3384	0.13%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.231	=	$0.0000	0.0	GJ x	$1.327	=	$0.0000	$0.096	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	=	$0.0000	6,732.4	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	$0.000	=	$0.0000	6,732.4	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$5,756.20**					**$6,200.54**		**$444.34**	**0.13%**
18														
19	Non-Standard Charges (not forecast)													
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
21														
22	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
23														
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.713*		**$330,885.85**	464,078.2		*$0.759*		**$352,234.85**	*$0.046*	**$21,349.00**	**6.45%**
25														
26														
27	**COLUMBIA SERVICE - ELKVIEW COAL**													
28	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
29														
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.947	=	**$62,381.88**	2,670.0	GJ x	$2.099	=	**$67,251.96**	$0.152	**$4,870.08**	**2.70%**
31														
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.092	=	$58,102.9220	631,553.5	GJ x	$0.099	=	$62,523.7965	$0.007	$4,420.8745	2.45%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	=	$0.0000	631,553.5	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	$0.000	=	$0.0000	631,553.5	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
35	Transportation - Firm (Delivery Charge Firm MTQ)					**$58,102.92**					**$62,523.80**		**$4,420.88**	**2.45%**
36														
37	Delivery Charge - Interruptible MTQ													
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.214	=	$0.0000	0.0	GJ x	$0.231	=	$0.0000	$0.017	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.306	=	$4,437.9486	14,503.1	GJ x	$0.330	=	$4,786.0230	$0.024	$348.0744	0.19%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$4,437.95**					**$4,786.02**		**$348.07**	**0.19%**
44														
45	Non-Standard Charges (not forecast)													
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
47														
48	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
49														
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.279*		**$180,302.75**	646,056.6		*$0.294*		**$189,941.78**	*$0.015*	**$9,639.03**	**5.35%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1										
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$132.52	= **$1,590.24**	12 months x	$132.52	= **$1,590.24**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	4,100.0 GJ x	$2.467	= $10,114.7000	4,100.0 GJ x	$2.655	= $10,885.5000	$0.188	$770.8000	6.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0 GJ x	$0.000	= $0.0000	4,100.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0 GJ x	$0.000	= $0.0000	4,100.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Rider 5 RSAM	4,100.0 GJ x	($0.032)	= ($131.2000)	4,100.0 GJ x	($0.032)	= ($131.2000)	$0.000	$0.0000	0.00%
11	Transportation - Firm			**$9,983.50**			**$10,754.30**		**$770.80**	**6.16%**
12										
13	Non-Standard Charges (not forecast)									
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
15										
16	Total *(with effective $/GJ rate)*	4,100.0	*$3.051*	**$12,509.74**	4,100.0	*$3.239*	**$13,280.54**	*$0.188*	**$770.80**	**6.16%**
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$132.52	= **$1,590.24**	12 months x	$132.52	= **$1,590.24**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	4,700.0 GJ x	$2.467	= $11,594.9000	4,700.0 GJ x	$2.655	= $12,478.5000	$0.188	$883.6000	6.32%
24	Rider 2 2009 ROE Rate Rider	4,700.0 GJ x	$0.000	= $0.0000	4,700.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0 GJ x	$0.000	= $0.0000	4,700.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
26	Rider 5 RSAM	4,700.0 GJ x	($0.032)	= ($150.4000)	4,700.0 GJ x	($0.032)	= ($150.4000)	$0.000	$0.0000	0.00%
27	Transportation - Firm			**$11,444.50**			**$12,328.10**		**$883.60**	**6.32%**
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
31										
32	Total *(with effective $/GJ rate)*	4,700.0	*$2.972*	**$13,970.74**	4,700.0	*$3.160*	**$14,854.34**	*$0.188*	**$883.60**	**6.32%**
33										
34	**COLUMBIA SERVICE AREA**									
35	Basic Charge	12 months x	$132.52	= **$1,590.24**	12 months x	$132.52	= **$1,590.24**	$0.00	**$0.00**	**0.00%**
36										
37	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
38										
39	Delivery Charge	4,200.0 GJ x	$2.467	= $10,361.4000	4,200.0 GJ x	$2.655	= $11,151.0000	$0.188	$789.6000	6.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0 GJ x	$0.000	= $0.0000	4,200.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0 GJ x	$0.000	= $0.0000	4,200.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 5 RSAM	4,200.0 GJ x	($0.032)	= ($134.4000)	4,200.0 GJ x	($0.032)	= ($134.4000)	$0.000	$0.0000	0.00%
43	Transportation - Firm			**$10,227.00**			**$11,016.60**		**$789.60**	**6.19%**
44										
45	Non-Standard Charges (not forecast)									
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
47										
48	Total *(with effective $/GJ rate)*	4,200.0	*$3.036*	**$12,753.24**	4,200.0	*$3.224*	**$13,542.84**	*$0.188*	**$789.60**	**6.19%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1										
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Transportation - Firm Demand	97.2 GJ x	$16.996	= **$19,824.12**	97.2 GJ x	$18.324	= **$21,373.08**	$1.328	**$1,548.96**	**3.77%**
8										
9	Delivery Charge	19,086.2 GJ x	$0.696	= $13,283.9952	19,086.2 GJ x	$0.761	= $14,524.5982	$0.065	$1,240.6030	3.02%
10	Rider 2 2009 ROE Rate Rider	19,086.2 GJ x	$0.000	= $0.0000	19,086.2 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2 GJ x	$0.000	= $0.0000	19,086.2 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
12	Transportation - Firm			**$13,284.00**			**$14,524.60**		**$1,240.60**	**3.02%**
13										
14	Non-Standard Charges (not forecast)	214								
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16										
17	Total *(with effective $/GJ rate)*	19,086.2	*$2.153*	**$41,088.12**	19,086.2	*$2.299*	**$43,877.68**	*$0.146*	**$2,789.56**	**6.79%**
18										
19	**INLAND SERVICE AREA**									
20	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
21										
22	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23										
24	Transportation - Firm Demand	212.6 GJ x	$16.996	= **$43,360.20**	212.6 GJ x	$18.324	= **$46,748.16**	$1.328	**$3,387.96**	**4.25%**
25										
26	Delivery Charge	40,670.5 GJ x	$0.696	= $28,306.6680	40,670.5 GJ x	$0.761	= $30,950.2505	$0.065	$2,643.5825	3.32%
27	Rider 2 2009 ROE Rate Rider	40,670.5 GJ x	$0.000	= $0.0000	40,670.5 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5 GJ x	$0.000	= $0.0000	40,670.5 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
29	Transportation - Firm			**$28,306.67**			**$30,950.25**		**$2,643.58**	**3.32%**
30										
31	Non-Standard Charges (not forecast)									
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
33										
34	Total *(with effective $/GJ rate)*	40,670.5	*$1.958*	**$79,646.87**	40,670.5	*$2.107*	**$85,678.41**	*$0.149*	**$6,031.54**	**7.57%**
35										
36	**COLUMBIA SERVICE**									
37	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
38										
39	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
40										
41	Transportation - Firm Demand	182.2 GJ x	$16.996	= **$37,160.04**	182.2 GJ x	$18.324	= **$40,063.56**	$1.328	**$2,903.52**	**4.38%**
42										
43	Delivery Charge	30,357.8 GJ x	$0.696	= $21,129.0288	30,357.8 GJ x	$0.761	= $23,102.2858	$0.065	$1,973.2570	2.98%
44	Rider 2 2009 ROE Rate Rider	30,357.8 GJ x	$0.000	= $0.0000	30,357.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8 GJ x	$0.000	= $0.0000	30,357.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
46	Transportation - Firm			**$21,129.03**			**$23,102.29**		**$1,973.26**	**2.98%**
47										
48	Non-Standard Charges (not forecast)									
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
50										
51	Total *(with effective $/GJ rate)*	30,357.8	*$2.183*	**$66,269.07**	30,357.8	*$2.344*	**$71,145.85**	*$0.161*	**$4,876.78**	**7.36%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	53,957.0 GJ x	$1.140	= $61,510.9800	53,957.0 GJ x	$1.226	= $66,151.2820	$0.086	$4,640.3020	6.36%
8	Rider 2 2009 ROE Rate Rider	53,957.0 GJ x	$0.000	= $0.0000	53,957.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0 GJ x	$0.000	= $0.0000	53,957.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Transportation - Interruptible			**$61,510.98**			**$66,151.28**		**$4,640.30**	**6.36%**
11										
12	Non-Standard Charges (not forecast)									
13	UOR, Balancing gas, Backstopping Gas									
14										
15	Total *(with effective $/GJ rate)*	53,957.0	*$1.353*	**$73,006.98**	53,957.0	*$1.439*	**$77,647.28**	*$0.086*	**$4,640.30**	**6.36%**
16										
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12.0 months x	$78.00	= **$936.00**	12.0 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	48,903.9 GJ x	$1.140	= $55,750.4460	48,903.9 GJ x	$1.226	= $59,956.1814	$0.086	$4,205.7354	6.25%
24	Rider 2 2009 ROE Rate Rider	48,903.9 GJ x	$0.000	= $0.0000	48,903.9 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9 GJ x	$0.000	= $0.0000	48,903.9 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
26	Transportation - Interruptible			**$55,750.45**			**$59,956.18**		**$4,205.73**	**6.25%**
27										
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas									
31		48,903.9	*$1.375*	**$67,246.45**	48,903.9	*$1.461*	**$71,452.18**	*$0.086*	**$4,205.73**	**6.25%**
32	Total *(with effective $/GJ rate)*									
33										
34										
35	**COLUMBIA SERVICE AREA**									
36	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
37										
38	Administration Charge	12.0 months x	$78.00	= **$936.00**	12.0 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
39										
40	Delivery Charge	7,733.8 GJ x	$1.140	= $8,816.5320	7,733.8 GJ x	$1.226	= $9,481.6388	$0.086	$665.1068	0.99%
41	Rider 2 2009 ROE Rate Rider	7,733.8 GJ x	$0.000	= $0.0000	7,733.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8 GJ x	$0.000	= $0.0000	7,733.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible			**$8,816.53**			**$9,481.64**		**$665.11**	**0.99%**
44										
45										
46	Non-Standard Charges (not forecast)									
47	UOR, Balancing gas, Backstopping Gas									
48		7,733.8	*$2.626*	**$20,312.53**	7,733.8	*$2.712*	**$20,977.64**	*$0.086*	**$665.11**	**0.99%**
49	Total *(with effective $/GJ rate)*									

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
1	**INLAND SERVICE AREA**													
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$3.531	=	$176.5500	50.0	GJ x	$3.856	=	$192.8000	$0.325	$16.2500	1.51%
8	Rider 2 2009 ROE Rate Rider	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 5 RSAM	50.0	GJ x	($0.032)	=	($1.6000)	50.0	GJ x	($0.032)	=	($1.6000)	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges			$3.499		**$317.03**			$3.824		**$333.28**		**$16.25**	**1.51%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$1.315	=	$65.7500	50.0	GJ x	$1.315	=	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$4.568	=	$228.4000	50.0	GJ x	$4.568	=	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$9.331	=	$466.5500	50.0	GJ x	$9.331	=	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges			$15.214		**$760.70**			$15.214		**$760.70**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$21.555*		**$1,077.73**	50.0		*$21.880*		**$1,093.98**	*$0.325*	**$16.25**	**1.51%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.907	=	$726.7500	250.0	GJ x	$3.152	=	$788.0000	$0.245	$61.2500	1.35%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032)	=	($8.0000)	250.0	GJ x	($0.032)	=	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges			$2.875		**$1,016.83**			$3.120		**$1,078.08**		**$61.25**	**1.35%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$4.568	=	$1,142.0000	250.0	GJ x	$4.568	=	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$8.254	=	$2,063.5000	250.0	GJ x	$8.254	=	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges			$14.123		**$3,530.75**			$14.123		**$3,530.75**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$18.190*		**$4,547.58**	250.0		*$18.435*		**$4,608.83**	*$0.245*	**$61.25**	**1.35%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.467	=	$11,101.5000	4,500.0	GJ x	$2.655	=	$11,947.5000	$0.188	$846.0000	1.11%
44	Rider 2 2009 ROE Rate Rider	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
46	Rider 5 RSAM	4,500.0	GJ x	($0.032)	=	($144.0000)	4,500.0	GJ x	($0.032)	=	($144.0000)	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges			$2.435		**$12,547.74**			$2.623		**$13,393.74**		**$846.00**	**1.11%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.999	=	$4,495.5000	4,500.0	GJ x	$0.999	=	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$4.568	=	$20,556.0000	4,500.0	GJ x	$4.568	=	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$8.556	=	$38,502.0000	4,500.0	GJ x	$8.556	=	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges			$14.123		**$63,553.50**			$14.123		**$63,553.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$16.911*		**$76,101.24**	4,500.0		*$17.099*		**$76,947.24**	*$0.188*	**$846.00**	**1.11%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2012 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Effective Rate January 1, 2010	Rate Changes	Proposed Rate January 1, 2012
	(1)	(2)	(3)	(4)
1	**APARTMENT GENERAL SERVICE (AGS)**			
2				
3	Basic Daily Charge	$1.3142	$0.0000	$1.3142
4	Energy Charge per GJ	$12.373	$0.000	$12.373
5				
6	Minimum Monthly Charge	$40.00	$0.00	$40.00
7				
8	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
9				
10	**RESIDENTIAL GENERAL SERVICE (RGS-1)**			
11				
12	Basic Daily Charge	$0.3450	$0.0000	$0.3450
13	Energy Charge per GJ	$14.325	$0.000	$14.325
14				
15	Minimum Monthly Charge	$10.50	$0.00	$10.50
16				
17	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
18				
19	**SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)**			
20				
21	Basic Daily Charge	$0.3105	$0.0000	$0.3105
22	Energy Charge per GJ	$16.940	$0.000	$16.940
23				
24	Minimum Monthly Charge	$9.45	$0.00	$9.45
25				
26	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
27				
28	**SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)**			
29				
30	Basic Daily Charge	$1.1016	$0.0000	$1.1016
31	Energy Charge per GJ	$16.455	$0.000	$16.455
32				
33	Minimum Monthly Charge	$33.53	$0.00	$33.53
34				
35	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
36				
37	**LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)**			
38				
39	Basic Daily Charge	$2.0041	$0.0000	$2.0041
40	Energy Charge per GJ	$13.353	$0.000	$13.353
41				
42	Minimum Monthly Charge	$61.00	$0.00	$61.00
43				
44	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
45				
46	**LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)**			
47				
48	Basic Daily Charge	$3.2138	$0.0000	$3.2138
49	Energy Charge per GJ	$12.311	$0.000	$12.311
50				
51	Minimum Monthly Charge	$97.82	$0.00	$97.82
52				
53	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
54				
55	**LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)**			
56				
57	Basic Daily Charge	$6.6205	$0.0000	$6.6205
58	Energy Charge per GJ	$12.015	$0.000	$12.015
59				
60	Minimum Monthly Charge	$201.51	$0.00	$201.51
61				
62	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			

Line No.	Particulars	Effective Rate January 1, 2010	Rate Changes	Proposed Rate January 1, 2012
	(1)	(2)	(3)	(4)
1	**LARGE COMMERCIAL SERVICE RATE NO. 13 (LCS-13)**			
2				
3	Basic Monthly Charge	$201.51	$0.00	$201.51
4	Energy Charge per GJ	$6.608	($0.907)	$5.701
5				
6	Minimum Monthly Charge	$201.51	$0.00	$201.51
7				
8	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
9				
10	**LARGE COMMERCIAL SERVICE RATE HIGH LOAD FACTOR (HLF)**			
11				
12	Basic Daily Charge	$8.2136	$0.0000	$8.2136
13	Demand Charge	$47.180	$0.000	$47.180
14	Energy Charge per GJ	$8.697	$0.000	$8.697
15				
16	Minimum Monthly Charge	$250.00	$0.00	$250.00
17				
18	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
19				
20	**LARGE COMMERCIAL SERVICE RATE INVERSE LOAD FACTOR 150% (ILF)**			
21				
22	Basic Daily Charge	$8.2136	$0.0000	$8.2136
23	Energy Charge per GJ	$10.097	$0.000	$10.097
24				
25	Minimum Monthly Charge	$250.00	$0.00	$250.00
26				
27	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
APARTMENT GENERAL SERVICE (AGS)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$1.3142	=	$480.00		365.25	days x	$1.3142	=	$480.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	1,364.1	GJ x	$12.373	=	$16,878.01		1,364.1	GJ x	$12.373	=	$16,878.01		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	1,364.1		*$12.725*		**$17,358.01**		1,364.1		*$12.725*		**$17,358.01**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RESIDENTIAL GENERAL SERVICE (RGS-1)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$0.345	=	$126.00		365.25	days x	$0.345	=	$126.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	58.6	GJ x	$14.325	=	$839.45		58.6	GJ x	$14.325	=	$839.45		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	58.6		*$16.475*		**$965.45**		58.6		*$16.475*		**$965.45**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$0.3105	=	$113.40		365.25	days x	$0.3105	=	$113.40		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	80.3	GJ x	$16.940	=	$1,360.28		80.3	GJ x	$16.940	=	$1,360.28		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	80.3		*$18.352*		**$1,473.68**		80.3		*$18.352*		**$1,473.68**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$1.1016	=	$402.36		365.25	days x	$1.1016	=	$402.36		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	312.6	GJ x	$16.455	=	$5,143.83		312.6	GJ x	$16.455	=	$5,143.83		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	312.6		*$17.742*		**$5,546.19**		312.6		*$17.742*		**$5,546.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$2.0041	=	$732.00		365.25	days x	$2.0041	=	$732.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	929.8	GJ x	$13.353	=	$12,415.62		929.8	GJ x	$13.353	=	$12,415.62		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	929.8		*$14.140*		**$13,147.62**		929.8		*$14.140*		**$13,147.62**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$3.2138	=	$1,173.84		365.25	days x	$3.2138	=	$1,173.84		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	2,361.9	GJ x	$12.311	=	$29,077.35		2,361.9	GJ x	$12.311	=	$29,077.35		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	2,361.9		*$12.808*		**$30,251.19**		2,361.9		*$12.808*		**$30,251.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$6.6205	=	$2,418.12		365.25	days x	$6.6205	=	$2,418.12		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	17,694.0	GJ x	$12.015	=	$212,593.41		17,694.0	GJ x	$12.015	=	$212,593.41		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	17,694.0		*$12.152*		**$215,011.53**		17,694.0		*$12.152*		**$215,011.53**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Proposed Rate January 1, 2012	Rate Changes	Proposed Rate January 1, 2013
	(1)	(2)	(3)	(4)
1	**APARTMENT GENERAL SERVICE (AGS)**			
2				
3	Basic Daily Charge	$1.3142	$0.0000	$1.3142
4	Energy Charge per GJ	$12.373	$0.000	$12.373
5				
6	Minimum Monthly Charge	$40.00	$0.00	$40.00
7				
8				
9				
10	**RESIDENTIAL GENERAL SERVICE (RGS-1)**			
11				
12	Basic Daily Charge	$0.3450	$0.0000	$0.3450
13	Energy Charge per GJ	$14.325	$0.000	$14.325
14				
15	Minimum Monthly Charge	$10.50	$0.00	$10.50
16				
17				
18				
19	**SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)**			
20				
21	Basic Daily Charge	$0.3105	$0.0000	$0.3105
22	Energy Charge per GJ	$16.940	$0.000	$16.940
23				
24	Minimum Monthly Charge	$9.45	$0.00	$9.45
25				
26				
27				
28	**SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)**			
29				
30	Basic Daily Charge	$1.1016	$0.0000	$1.1016
31	Energy Charge per GJ	$16.455	$0.000	$16.455
32				
33	Minimum Monthly Charge	$33.53	$0.00	$33.53
34				
35				
36				
37	**LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)**			
38				
39	Basic Daily Charge	$2.0041	$0.0000	$2.0041
40	Energy Charge per GJ	$13.353	$0.000	$13.353
41				
42	Minimum Monthly Charge	$61.00	$0.00	$61.00
43				
44				
45				
46	**LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)**			
47				
48	Basic Daily Charge	$3.2138	$0.0000	$3.2138
49	Energy Charge per GJ	$12.311	$0.000	$12.311
50				
51	Minimum Monthly Charge	$97.82	$0.00	$97.82
52				
53				
54				
55	**LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)**			
56				
57	Basic Daily Charge	$6.6205	$0.0000	$6.6205
58	Energy Charge per GJ	$12.015	$0.000	$12.015
59				
60	Minimum Monthly Charge	$201.51	$0.00	$201.51
61				
62				

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Proposed Rate January 1, 2012	Rate Changes	Proposed Rate January 1, 2013
	(1)	(2)	(3)	(4)
1	**LARGE COMMERCIAL SERVICE RATE NO. 13 (LCS-13)**			
2				
3	Basic Monthly Charge	$201.51	$0.00	$201.51
4	Energy Charge per GJ	$5.701	($0.128)	$5.573
5				
6	Minimum Monthly Charge	$201.51	$0.00	$201.51
7				
8				
9				
10	**LARGE COMMERCIAL SERVICE RATE HIGH LOAD FACTOR (HLF)**			
11				
12	Basic Daily Charge	$8.2136	$0.0000	$8.2136
13	Demand Charge	$47.180	$0.000	$47.180
14	Energy Charge per GJ	$8.697	$0.000	$8.697
15				
16	Minimum Monthly Charge	$250.00	$0.00	$250.00
17				
18				
19				
20	**LARGE COMMERCIAL SERVICE RATE INVERSE LOAD FACTOR 150% (ILF)**			
21				
22	Basic Daily Charge	$8.2136	$0.0000	$8.2136
23	Energy Charge per GJ	$10.097	$0.000	$10.097
24				
25	Minimum Monthly Charge	$250.00	$0.00	$250.00
26				
27				

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
APARTMENT GENERAL SERVICE (AGS)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$1.3142	=	$480.00		365.25	days x	$1.3142	=	$480.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	1,364.1	GJ x	$12.373	=	$16,878.01		1,364.1	GJ x	$12.373	=	$16,878.01		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	1,364.1		*$12.725*		**$17,358.01**		1,364.1		*$12.725*		**$17,358.01**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RESIDENTIAL GENERAL SERVICE (RGS-1)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$0.345	=	$126.00		365.25	days x	$0.345	=	$126.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	58.6	GJ x	$14.325	=	$839.45		58.6	GJ x	$14.325	=	$839.45		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	58.6		*$16.475*		**$965.45**		58.6		*$16.475*		**$965.45**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
1	**FortisBC Energy Vancouver Island**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
2																
3	Basic Daily Charge	365.25	days x	$0.3105	=	$113.40		365.25	days x	$0.3105	=	$113.40		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	80.3	GJ x	$16.940	=	$1,360.28		80.3	GJ x	$16.940	=	$1,360.28		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	80.3		*$18.352*		**$1,473.68**		80.3		*$18.352*		**$1,473.68**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$1.1016	=	$402.36		365.25	days x	$1.1016	=	$402.36		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	312.6	GJ x	$16.455	=	$5,143.83		312.6	GJ x	$16.455	=	$5,143.83		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	312.6		*$17.742*		**$5,546.19**		312.6		*$17.742*		**$5,546.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$2.0041	=	$732.00		365.25	days x	$2.0041	=	$732.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	929.8	GJ x	$13.353	=	$12,415.62		929.8	GJ x	$13.353	=	$12,415.62		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	929.8		*$14.140*		**$13,147.62**		929.8		*$14.140*		**$13,147.62**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$3.2138	=	$1,173.84		365.25	days x	$3.2138	=	$1,173.84		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	2,361.9	GJ x	$12.311	=	$29,077.35		2,361.9	GJ x	$12.311	=	$29,077.35		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	2,361.9		*$12.808*		**$30,251.19**		2,361.9		*$12.808*		**$30,251.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)

APPENDIX F-2
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PAGE 3

Line No.	Particular	Proposed January 1, 2012 Rates							Proposed Rate January 1, 2013 Rates							Annual Increase/Decrease		
		Volume			Rate		Annual $		Volume			Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**																	
2																		
3	Basic Daily Charge	365.25	days	x	$6.6205	=	$2,418.12		365.25	days	x	$6.6205	=	$2,418.12		$0.0000	$0.00	0.00%
4																		
5	Energy Charge per GJ	17,694.0	GJ	x	$12.015	=	$212,593.41		17,694.0	GJ	x	$12.015	=	$212,593.41		$0.000	$0.00	0.00%
6																		
7	**Total *(with effective $/GJ rate)***	17,694.0			*$12.152*		**$215,011.53**		17,694.0			*$12.152*		**$215,011.53**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Effective Rate January 1, 2011	Proposed Rate January 1, 2012	Increase / (Decrease)	% Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.440	$10.680	$0.2400	2.30%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.263**	**$16.503**	**$0.2400**	**1.48%**
8						
9	Rider A	*($/GJ)*	($0.948)	$0.000	$0.948	-100.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.000	$0.524	$0.524	n/a
12	Total Riders	*($/GJ)*	**($0.948)**	**$0.524**	**$1.472**	**255.27%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 15.315**	**$ 17.027**	**$ 1.712**	**11.18%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,468.35	$1,622.43		
22						
23	Change in Annual Bill	*($)*			**$ 154.08**	
24	Change in Annual Bill	*(%)*			**10.49%**	

Note: Existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Proposed Rate January 1, 2012	Proposed Rate January 1, 2013	Increase / (Decrease)	Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.680	$11.963	$1.2830	12.01%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.503**	**$17.786**	**$1.2830**	**7.77%**
8						
9	Rider A	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.524	$0.524	$0.000	0.00%
12	Total Riders	*($/GJ)*	**$0.524**	**$0.524**	**$0.000**	**0.00%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 17.027**	**$ 18.310**	**$ 1.283**	**7.54%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,622.43	$1,737.90		
22						
23	Change in Annual Bill	*($)*			**$ 115.47**	
24	Change in Annual Bill	*(%)*			**7.12%**	

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	EXISTING RATE JANUARY 1, 2011	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3141	$0.0199	$0.3340
10			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
12			**Minimum Daily Charge** (includes first 2 gigajoules/month)	**$0.646**	$0.017	**$0.663**
13						
14			Delivery Charge per GJ	$2.410	$0.160	$2.570
15			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
16			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
17			**Next 28 Gigajoules in any month**	**$7.458**	$0.116	**$7.574**
18						
19			Delivery Charge per GJ	$2.340	$0.162	$2.502
20			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
21			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
22			**Excess of 30 Gigajoules in any month**	**$7.388**	$0.118	**$7.506**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3141	$0.0199	$0.3340
28			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
30			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$0.646**	$0.017	**$0.663**
31						
32			Delivery Charge per GJ	$2.410	$0.160	$2.570
33			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
34			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
35			**Next 28 Gigajoules in any month**	**$7.458**	$0.116	**$7.574**
36						
37			Delivery Charge per GJ	$2.340	$0.162	$2.502
38			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
39			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
40			**Excess of 30 Gigajoules in any month**	**$7.388**	$0.118	**$7.506**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATE	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATE
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9193	$0.0654	$0.9847
2			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.0029)	($0.0007)
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
4			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.251**	$0.063	**$1.314**
5						
6			Delivery Charge per GJ	$2.710	$0.181	$2.891
7			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
8			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
9			**Next 28 Gigajoules in any month**	**$7.758**	$0.137	**$7.895**
10						
11			Delivery Charge per GJ	$2.624	$0.176	$2.800
12			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
13			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
14			**Excess of 30 Gigajoules in any month**	**$7.672**	$0.132	**$7.804**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9193	$0.0654	$0.9847
17			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
19			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.251**	$0.063	**$1.314**
20						
21			Delivery Charge per GJ	$2.710	$0.181	$2.891
22			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
23			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
24			**Next 28 Gigajoules in any month**	**$7.758**	$0.137	**$7.895**
25						
26			Delivery Charge per GJ	$2.624	$0.176	$2.800
27			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
28			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
29			**Excess of 30 Gigajoules in any month**	**$7.672**	$0.132	**$7.804**
30						
31	Rate 2.3	No. 2.1	Delivery Charge per Month	$28.08	$1.83	$29.91
32			Gas Cost Recovery Charge per Month	$10.030	$0.00	$10.030
33			**Minimum Monthly Charge** (includes first 2 gigajoules)	**$38.110**	$1.827	**$39.937**
34						
35			Delivery Charge per GJ	$3.450	$0.225	$3.675
36			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
37			**Next 28 Gigajoules in any month**	**$8.465**	$0.225	**$8.690**
38						
39			Delivery Charge per GJ	$3.362	$0.219	$3.581
40			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
41			**Excess of 30 Gigajoules in any month**	**$8.377**	$0.219	**$8.596**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATE	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATE
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
5			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
8			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
9						
10			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
16			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
17			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
20			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
21						
22			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
28			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
29			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
32			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
33						
34			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATES	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
5			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
6						
7			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	$0.033	($0.044)	($0.011)

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/(Decrease)		
1	**Rate 1 Domestic Service Option B**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per day	365.25	days x	$0.3141	$114.7200	365.25	days x	$0.3340	$121.9800	$0.0199	$7.2600	0.66%
5	Rider 5 - RSAM per day	365.25	days x	$0.0022	$0.8036	365.25	days x	($0.0007)	-$0.2557	($0.0029)	($1.0592)	-0.10%
6	Gas Cost Recovery Charge per Day	365.25	days x	$0.3295	$120.3499	365.25	days x	$0.3295	$120.3499	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$0.6458	$235.8700			$0.6628	$242.0700	$0.0170	$6.2000	0.56%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$2.410	$279.5600	116	GJ x	$2.570	$298.1200	$0.160	$18.5600	1.69%
11	Rider 5 - RSAM per GJ	116	GJ x	$0.033	$3.8280	116	GJ x	($0.011)	($1.2760)	($0.044)	($5.1040)	-0.46%
12	Gas Cost Recovery Charge per GJ	116	GJ x	$5.015	$581.7400	116	GJ x	$5.015	$581.7400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.458	$865.1300			$7.574	$878.5800	$0.116	$13.4500	1.22%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.340	$0.0000	0	GJ x	$2.502	$0.0000	$0.162	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	$0.033	$0.0000	0	GJ x	($0.011)	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.388	$0.0000			$7.506	$0.0000	$0.118	$0.0000	0.00%
20												
21	Total	140	GJ		$1,101.00	140	GJ		$1,120.65		$19.65	1.78%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$398.91				$418.57		$19.66	1.79%
25	Commodity Charge				$702.09				$702.09		$0.00	0.00%
26	Total				$1,101.00				$1,120.66		$19.66	1.79%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/(Decrease)		
1	**Rate 2.1 General Service**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per month	365.25	days x	$0.9193	$335.7600	365.25	months x	$0.9847	$359.6520	$0.0654	$23.8920	0.62%
5	Rider 5 - RSAM per month	365.25	days x	$0.0022	$0.8036	365.25	months x	($0.0007)	($0.2557)	($0.0029)	($1.0592)	-0.03%
6	Gas Cost Recovery Charge per month	365.25	days x	$0.3300	$120.5325	365.25	months x	$0.3300	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.2515	$457.1000			$1.3140	$479.9300	$0.0625	$22.8300	0.59%
8												
9	Next 298 Gigajoules in any month											
10	Delivery Charge per GJ	436	GJ x	$2.710	$1,181.5600	436	GJ x	$2.891	$1,260.4760	$0.181	$78.9160	2.06%
11	Rider 5 - RSAM per GJ	436	GJ x	$0.033	$14.3880	436	GJ x	($0.011)	($4.7960)	($0.044)	($19.1840)	-0.50%
12	Gas Cost Recovery Charge per GJ	436	GJ x	$5.015	$2,186.5400	436	GJ x	$5.015	$2,186.5400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.758	$3,382.4900			$7.895	$3,442.2200	$0.137	$59.7300	1.56%
14												
15	Excess of 300 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.624	$0.0000	0	GJ x	$2.800	$0.0000	$0.176	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	$0.033	$0.0000	0	GJ x	($0.011)	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.672	$0.0000			$7.804	$0.0000	$0.132	$0.0000	0.00%
20												
21	Total	460	GJ		$3,839.59	460	GJ		$3,922.15		$82.56	2.15%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$1,532.51				$1,615.08		$82.56	2.15%
25	Commodity Charge				$2,307.07				$2,307.07		$0.00	0.00%
26	Total				$3,839.58				$3,922.15		$82.57	2.15%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/(Decrease)		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.2 General Service**													
2														
3	Daily Charge													
4	Delivery Charge per day	365.25	days x	$0.9193	=	$335.7600	365.25	days x	$0.9847	=	$359.6520	$0.0654	$23.8920	0.10%
5	Rider 5 - RSAM per day	365.25	days x	$0.0022	=	$0.8036	365.25	days x	($0.0007)	=	-$0.2557	($0.0029)	-$1.0592	0.00%
6	Gas Cost Recovery Charge per day	365.25	days x	$0.3300	=	$120.5325	365.25	days x	$0.3300	=	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.2515		$457.1000			$1.3140		$479.9300	$0.0625	$22.8300	0.09%
8														
9	Next 298 Gigajoules in any month													
10	Delivery Charge per GJ	3,076	GJ x	$2.710	=	$8,335.9600	3,076	GJ x	$2.891	=	$8,892.7160	$0.181	$556.7560	2.29%
11	Rider 5 - RSAM per GJ	3,076	GJ x	$0.033	=	$101.5080	3,076	GJ x	($0.011)	=	($33.8360)	($0.044)	($135.3440)	-0.56%
12	Gas Cost Recovery Charge per GJ	3,076	GJ x	$5.015	=	$15,426.1400	3,076	GJ x	$5.015	=	$15,426.1400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.758		$23,863.6100			$7.895		$24,285.0200	$0.137	$421.4100	1.73%
14														
15	Excess of 300 Gigajoules in any month													
16	Delivery Charge per GJ	0	GJ x	$2.624	=	$0.0000	0	GJ x	$2.800	=	$0.0000	$0.176	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	$0.033	=	$0.0000	0	GJ x	($0.011)	=	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	=	$0.0000	0	GJ x	$5.015	=	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.672		$0.0000			$7.804		$0.0000	$0.132	$0.0000	0.00%
20														
21	Total	3,100	GJ			$24,320.71	3,100	GJ			$24,764.95		$444.24	1.83%
22														
23	Summary of Annual Delivery and Commodity Charges													
24	Delivery Charge (including RSAM)					$8,774.03					$9,218.28		$444.24	1.83%
25	Commodity Charge					$15,546.67					$15,546.67		$0.00	0.00%
26	Total					$24,320.70					$24,764.95		$444.25	1.83%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11

RATE 25 - TRANSPORTATION SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2														
3	Transportation Delivery Charges													
4														
5	Delivery Charge per Gigajoule													
6	i) First 20 Gigajoules	240	GJ x	$2.910	=	$698.4000	240	GJ x	$2.910	=	$698.4000	$0.000	$0.0000	0.00%
7	ii) Next 260 Gigajoules	3,120	GJ x	$2.690	=	$8,392.8000	3,120	GJ x	$2.926	=	$9,129.1200	0.236	$736.3200	3.79%
8	iii) Excess over 280 Gigajoules	3,530	GJ x	$2.174	=	$7,674.2200	3,530	GJ x	$2.333	=	$8,235.4900	0.159	$561.2700	2.89%
9	iv) Minimum Delivery Charge per month	12	months x	$1,826.00			12	months x	$1,945.00			$119.00	$0.0000	0.00%
10														
11	Administration Charge per month	12	months x	$202.00	=	$2,424.0000	12	months x	$202.00	=	$2,424.0000	$0.00	$0.0000	0.00%
12														
13	Rider 5: RSAM per GJ	6,890	GJ x	$0.033	=	$227.3700	6,890	GJ x	($0.011)	=	($75.7900)	($0.044)	($303.1600)	-1.56%
14														
15	Total Transportation Delivery & Administration Charges	6,890	GJ x	*$2.818*		$19,416.79	6,890	GJ x	*$2.962*		$20,411.22	*$0.144*	$994.43	5.12%
16														
17														
18	Summary of Annual Delivery, Administration and Commodity Charges													
19	Delivery & Administration Charge (including RSAM)	6,890	GJ x	$2.818	=	$19,416.7900	6,890	GJ x	$2.962	=	$20,411.2200	$0.144	$994.4300	5.12%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ	$0.000	=	$0.0000	0	GJ	$0.000	=	$0.0000	0.000	$0.0000	0.00%
21	Total	6,890	GJ x	*$2.818*	=	$19,416.79	6,890	GJ x	*$2.962*	=	$20,411.22	*$0.144*	$994.43	5.12%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule (1)	Tariff Page (2)	Particulars (3)	PROPOSED RATE JANUARY 1, 2012 (4)	Delivery Related Changes (5)	EFFECTIVE RATE JANUARY 1, 2013 (6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3340	$0.0055	$0.3394
10			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
12			**Minimum Daily Charge** (includes first 2 gigajoules/month)	**$0.663**	$0.005	**$0.668**
13						
14			Delivery Charge per GJ	$2.570	$0.042	$2.612
15			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
16			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
17			**Next 28 Gigajoules in any month**	**$7.574**	$0.042	**$7.616**
18						
19			Delivery Charge per GJ	$2.502	($0.001)	$2.501
20			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
21			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
22			**Excess of 30 Gigajoules in any month**	**$7.506**	($0.001)	**$7.505**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3340	$0.0055	$0.3394
28			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
30			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$0.663**	$0.005	**$0.668**
31						
32			Delivery Charge per GJ	$2.570	$0.042	$2.612
33			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
34			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
35			**Next 28 Gigajoules in any month**	**$7.574**	$0.042	**$7.616**
36						
37			Delivery Charge per GJ	$2.502	($0.001)	$2.501
38			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
39			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
40			**Excess of 30 Gigajoules in any month**	**$7.506**	($0.001)	**$7.505**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	PROPOSED RATE JANUARY 1, 2012	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9847	$0.0159	$1.0005
2			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.0000	($0.0007)
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
4			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.314**	$0.016	**$1.330**
5						
6			Delivery Charge per GJ	$2.891	$0.043	$2.934
7			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
8			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
9			**Next 28 Gigajoules in any month**	**$7.895**	$0.043	**$7.938**
10						
11			Delivery Charge per GJ	$2.800	$0.029	$2.829
12			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
13			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
14			**Excess of 30 Gigajoules in any month**	**$7.804**	$0.029	**$7.833**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9847	$0.0159	$1.0005
17			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
19			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.314**	$0.016	**$1.330**
20						
21			Delivery Charge per GJ	$2.891	$0.043	$2.934
22			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
23			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
24			**Next 28 Gigajoules in any month**	**$7.895**	$0.043	**$7.938**
25						
26			Delivery Charge per GJ	$2.800	$0.029	$2.829
27			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
28			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
29			**Excess of 30 Gigajoules in any month**	**$7.804**	$0.029	**$7.833**
30						
31	Rate 2.3	No. 2.1	Delivery Charge per Month	$29.91	$2.44	$32.35
32			Gas Cost Recovery Charge per Month	$10.030	$0.00	$10.030
33			**Minimum Monthly Charge** (includes first 2 gigajoules)	**$39.937**	$2.443	**$42.380**
34						
35			Delivery Charge per GJ	$3.675	$0.300	$3.975
36			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
37			**Next 28 Gigajoules in any month**	**$8.690**	$0.300	**$8.990**
38						
39			Delivery Charge per GJ	$3.581	$0.293	$3.874
40			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
41			**Excess of 30 Gigajoules in any month**	**$8.596**	$0.293	**$8.889**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	PROPOSED RATE JANUARY 1, 2012	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
4			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
5			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
8			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
9						
10			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
16			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
17			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
20			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
21						
22			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
28			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
29			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
32			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
33						
34			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2012 PROPOSED RATES	Delivery Related Changes	JANUARY 1, 2013 EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.926	$0.000	$2.926
5			Excess over 280 Gigajoules in any month	$2.333	$0.040	$2.373
6						
7			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	($0.011)	$0.000	($0.011)

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/(Decrease)		
1	**Rate 1 Domestic Service Option B**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per day	365.25	days x	$0.3340	$121.9800	365.25	days x	$0.3394	$123.9840	$0.0055	$2.0040	0.18%
5	Rider 5 - RSAM per day	365.25	days x	($0.0007)	-$0.2557	365.25	days x	($0.0007)	-$0.2557	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per Day	365.25	days x	$0.3295	$120.3499	365.25	days x	$0.3295	$120.3499	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$0.6628	$242.0700			$0.6682	$244.0800	$0.0055	$2.0100	0.18%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$2.570	$298.1200	116	GJ x	$2.612	$302.9920	$0.042	$4.8720	0.43%
11	Rider 5 - RSAM per GJ	116	GJ x	($0.011)	($1.2760)	116	GJ x	($0.011)	($1.2760)	$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	116	GJ x	$5.015	$581.7400	116	GJ x	$5.015	$581.7400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.574	$878.5800			$7.616	$883.4600	$0.042	$4.8800	0.44%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.502	$0.0000	0	GJ x	$2.501	$0.0000	($0.001)	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	$0.0000	0	GJ x	($0.011)	$0.0000	$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.506	$0.0000			$7.505	$0.0000	($0.001)	$0.0000	0.00%
20												
21	Total	140	GJ		$1,120.65	140	GJ		$1,127.54		$6.89	0.61%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$418.57				$425.44		$6.88	0.61%
25	Commodity Charge				$702.09				$702.09		$0.00	0.00%
26	Total				$1,120.66				$1,127.53		$6.87	0.61%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/(Decrease)		
1	**Rate 2.1 General Service**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per month	365.25	days x	$0.9847	$359.6520	365.25	months x	$1.0005	$365.4480	$0.0159	$5.7960	0.15%
5	Rider 5 - RSAM per month	365.25	days x	($0.0007)	($0.2557)	365.25	months x	($0.0007)	($0.2557)	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per month	365.25	days x	$0.3300	$120.5325	365.25	months x	$0.3300	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.3140	$479.9300			$1.3298	$485.7200	$0.0159	$5.7900	0.15%
8												
9	Next 298 Gigajoules in any month											
10	Delivery Charge per GJ	436	GJ x	$2.891	$1,260.4760	436	GJ x	$2.934	$1,279.2240	$0.043	$18.7480	0.48%
11	Rider 5 - RSAM per GJ	436	GJ x	($0.011)	-$4.7960	436	GJ x	($0.011)	($4.7960)	$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	436	GJ x	$5.015	$2,186.5400	436	GJ x	$5.015	$2,186.5400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.895	$3,442.2200			$7.938	$3,460.9700	$0.043	$18.7500	0.48%
14												
15	Excess of 300 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.800	$0.0000	0	GJ x	$2.829	$0.0000	$0.029	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	$0.0000	0	GJ x	($0.011)	$0.0000	$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.804	$0.0000			$7.833	$0.0000	$0.029	$0.0000	0.00%
20												
21	Total	460	GJ		$3,922.15	460	GJ		$3,946.69		$24.54	0.63%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$1,615.08				$1,639.62		$24.54	0.63%
25	Commodity Charge				$2,307.07				$2,307.07		$0.00	0.00%
26	Total				$3,922.15				$3,946.69		$24.54	0.63%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES						PROPOSED JANUARY 1, 2013 RATES						Annual Increase/(Decrease)		
1	**Rate 2.2 General Service**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2																
3	Daily Charge															
4	Delivery Charge per day	365.25	days x	$0.9847	=	$359.6520		365.25	days x	$1.0005	=	$365.4480		$0.0159	$5.7960	0.02%
5	Rider 5 - RSAM per day	365.25	days x	($0.0007)	=	($0.2557)		365.25	days x	($0.0007)	=	-$0.2557		$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per day	365.25	days x	$0.3300	=	$120.5325		365.25	days x	$0.3300	=	$120.5325		$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.3140		$479.9300				$1.3298		$485.7200		$0.0159	$5.7900	0.02%
8																
9	Next 298 Gigajoules in any month															
10	Delivery Charge per GJ	3,076	GJ x	$2.891	=	$8,892.7160		3,076	GJ x	$2.934	=	$9,024.9840		$0.043	$132.2680	0.53%
11	Rider 5 - RSAM per GJ	3,076	GJ x	($0.011)	=	($33.8360)		3,076	GJ x	($0.011)	=	($33.8360)		$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	3,076	GJ x	$5.015	=	$15,426.1400		3,076	GJ x	$5.015	=	$15,426.1400		$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.895		$24,285.0200				$7.938		$24,417.2900		$0.043	$132.2700	0.53%
14																
15	Excess of 300 Gigajoules in any month															
16	Delivery Charge per GJ	0	GJ x	$2.800	=	$0.0000		0	GJ x	$2.829	=	$0.0000		$0.029	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	=	$0.0000		0	GJ x	($0.011)	=	$0.0000		$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	=	$0.0000		0	GJ x	$5.015	=	$0.0000		$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.804		$0.0000				$7.833		$0.0000		$0.029	$0.0000	0.00%
20																
21	Total	3,100	GJ			$24,764.95		3,100	GJ			$24,903.01			$138.06	0.56%
22																
23	Summary of Annual Delivery and Commodity Charges															
24	Delivery Charge (including RSAM)					$9,218.28						$9,356.34			$138.06	0.56%
25	Commodity Charge					$15,546.67						$15,546.67			$0.00	0.00%
26	Total					$24,764.95						$24,903.01			$138.06	0.56%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11

RATE 25 - TRANSPORTATION SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES							PROPOSED JANUARY 1, 2013 RATES							Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume			Rate		Annual $		Volume			Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2																		
3	Transportation Delivery Charges																	
4																		
5	Delivery Charge per Gigajoule																	
6	i) First 20 Gigajoules	240	GJ	x	$2.910	=	$698.4000		240	GJ	x	$2.910	=	$698.4000		$0.000	$0.0000	0.00%
7	ii) Next 260 Gigajoules	3,120	GJ	x	$2.926	=	$9,129.1200		3,120	GJ	x	$2.926	=	$9,129.1200		0.000	$0.0000	0.00%
8	iii) Excess over 280 Gigajoules	3,530	GJ	x	$2.333	=	$8,235.4900		3,530	GJ	x	$2.373	=	$8,376.6900		0.040	$141.2000	0.69%
9	iv) Minimum Delivery Charge per month	12	months	x	$1,945.00				12	months	x	$1,975.00				$30.00	$0.0000	0.00%
10																		
11	Administration Charge per month	12	months	x	$202.00	=	$2,424.0000		12	months	x	$202.00	=	$2,424.0000		$0.00	$0.0000	0.00%
12																		
13	Rider 5: RSAM per GJ	6,890	GJ	x	($0.011)	=	($75.7900)		6,890	GJ	x	($0.011)	=	($75.7900)		$0.000	$0.0000	0.00%
14																		
15	Total Transportation Delivery & Administration Charges	6,890	GJ	x	*$2.962*		$20,411.22		6,890	GJ	x	*$2.983*		$20,552.42		*$0.021*	$141.20	0.69%
16																		
17																		
18	Summary of Annual Delivery, Administration and Commodity Charges																	
19	Delivery & Administration Charge (including RSAM)	6,890	GJ	x	$2.962	=	$20,411.2200		6,890	GJ	x	$2.983	=	$20,552.4200		$0.021	$141.2000	0.69%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ		$0.000	=	$0.0000		0	GJ		$0.000	=	$0.0000		0.000	$0.0000	0.00%
21	Total	6,890	GJ	x	*$2.962*	=	$20,411.22		6,890	GJ	x	*$2.983*	=	$20,552.42		*$0.021*	$141.20	0.69%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

Appendix G

NON RATE BASE DEFERRAL ACCOUNTS

1 OVERVIEW

The FortisBC Energy Utilities maintain both rate base and non rate base deferral accounts. The recommendation for one treatment over the other has primarily been one of timing, or as a means to stream cost recovery to a particular customer or group of customers separate from all other customers. In the case of a timing issue, if the FBU are able to forecast balances for deferral accounts and include them in revenue requirements, then that is the preferred treatment. In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, that deferral account will be non-rate base attracting AFUDC until such time as rates are re-set under the next revenue requirement, and the account is rolled into rate base. Consistent with the Uniform System of Accounts, items that are recoverable from customers but not included in rate base (such as Work in Progress or non-rate base deferral accounts) are afforded AFUDC treatment so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

The following two sections discuss the existing non rate base deferral accounts for the Mainland and Vancouver Island. Neither Whistler nor Fort Nelson have non rate base deferral accounts.

2 MAINLAND

2.1 Biomethane Variance Account (BVA)

The Commission approved the creation of the BVA in its Order No. G-194-10, to capture costs to procure and process consumable biomethane gas as well as revenues collected through the biomethane energy recovery component of rates. The BVA captures biomethane commodity costs, the capital cost of service of the upgrader plant[1], O&M associated with the upgrader plant and O&M costs attributable to biomethane customer enrolment, account finalization and billing adjustments. The balance in the BVA is recovered through the Biomethane Energy Recovery Charge. Please refer to Appendix J for a comprehensive report on the biomethane program and details regarding the balance of all deferral accounts associated with biomethane.

2.2 Commodity Unbundling

At the end of 2010, the Commercial Commodity Unbundling deferral had a balance of $52.3 thousand, and the Residential Commodity Unbundling deferral had a balance of $102 thousand. Both of these deferral accounts are forecast to have a zero balance at the end of 2011, as the currently approved Rider 8 is forecast to recover the balance in the accounts. FEI projects that the marketer fee recoveries for these programs in the future will be sufficient to recover the ongoing costs, and is therefore requesting that these accounts be discontinued effective January 1, 2012. The costs and recoveries will be recorded in O&M starting in 2012, and have

1 As discussed in Section 5.5, Biomethane Recoveries are included in other revenue and transfer the capital cost of service of the upgrader plant from the delivery margin to the BVA

been forecast as net zero for this RRA, with the exception of the Customer Choice program expenditures which are included in the Customer Service department O&M discussed in Section 5.3.7.

2.3 Tilbury Property Purchase (Subdividable Land)

Approved by Commission Order No. G-68-10, the Tilbury Property Purchase deferral account had a balance of $3.353 million at the end of 2010. This represents the original allocation of the subdividable area ($3.3 million) plus interest recorded to date. As identified in the Tilbury CPCN application, and as required by Order G-68-10, FEI was to investigate opportunities to subdivide and sell a portion of the Tilbury Property not required for compliance purposes. On December 1, 2010, in compliance with Order G-68-10, FEI filed its semi-annual report with respect to its efforts to subdivide and sell a portion of the Tilbury Property. FEI continues to work with several parties and expects to file an application for approval of a subdivision and sale sometime before year end. The disposition of the Tilbury Property Purchase deferral account will be dealt with as part of that subdivision and sale application.

2.4 Thermal Energy Services[2] (formerly Alternative Energy Services)

FEI continues to work with customers in defining and developing their integrated energy needs. In response to those needs, development is underway on several Thermal Energy Services projects. FEI will be seeking appropriate Commission approvals for each project pursuant to item 8 of the Negotiated Settlement Agreement approved by Order G-141-09, dated November 26, 2009. These projects will come forward for BCUC approval once contracts are in place with customers. FEI expects to begin filing these contracts in the Spring or Summer of 2011 with the BCUC.

The market interest for Thermal Energy solutions is considerable. FEI currently has over 20 projects in development with a total estimated value exceeding $250 million. Several of these projects are anticipated to be submitted to the BCUC for approval in the near term. Table G-1 provides examples of some of the current Thermal Energy Services projects under development.

Table G-1: Customers are Seeking Complete Integrated Energy Solutions

Project	Description
Quesnel District Energy System, Quesnel, B.C.	FEI is developing a combined power and district heating project in the City. The project will use waste heat from the nearby pulp and paper mill to heat up to 22 buildings and generate about 1.7 megawatts of electricity. Natural gas will also continue to be an important part of the City's energy mix.

2 Thermal Energy Services means Geoexchange, Solar-thermal and District Energy Systems.

Project	Description
The Village at Fraser Mills, Coquitlam, B.C.	This district energy system will serve a new mixed-use community of up to 3,700 residential units; 150,000 square feet of commercial space; 100,000 square feet of institutional space; 235,000 square feet of industrial space; and a 44,000 square foot community building. The integrated energy solution being developed by FEI will include renewable thermal energy technology such as biomass or groundwater geoexchange.
Delta School District Geoexchange System, Delta, B.C.	FEI has an agreement with the Delta School District for the delivery of cleaner thermal energy for 17 schools and two school district buildings through the implementation of state-of-the-art geoexchange systems and high-efficiency condensing boilers, which will replace aging heating plants at school district sites. These systems provide many benefits, ranging from saving energy and improving indoor comfort to stable energy rates and a smaller carbon footprint.
City Centre and Pandosy Energy Systems, Kelowna, B.C.	FortisBC and the City of Kelowna have agreed in principle to develop two district energy systems. These FEI -owned and operated systems will use waste heat and water from the City's wastewater plant and a nearby industry as part of an integrated energy approach that can potentially save about 16,300 tonnes of CO2 per year – equivalent to removing approximately 3,500 cars from the road annually – according to the City's 2010 pre-feasibility study.

The Thermal Energy Services Deferral account was approved by Commission Order No. G-141-09 to capture and record revenues and costs related to geo-exchange, solar-thermal and district energy systems. FEI is proposing to continue segregating all costs and recoveries in this manner and is seeking approval for the continuation of the Thermal Energy Service Deferral Account in this Application. The recovery from Thermal Energy Services customers of the balance in this deferral account will be considered in FEI's future applications regarding individual contracts for approval by the BCUC. Consistent with the terms of the NSA, there are three components of costs charged to this deferral account, which are discussed in the following sections and include:

- Direct costs;
- Sales and marketing O&M and business development costs; and
- An overhead allocation from FEI.

All costs associated with Thermal Energy Services are included in the deferral account. Table G-2 summarizes the forecast costs added to the deferral account and attributable to Thermal Energy Services for 2010 and 2011, as agreed upon in the NSA, and also provides a comparison to the actual 2010 costs and the projected 2011 costs.

Table G-2: Thermal Energy Projects are in Development Stages

	2010			2011		
	NSA	Actual	Variance	NSA	Projected	Variance
Direct Costs	-	1,196	1,196	-	11,750	11,750
Sales & Marketing	1,000	1,435	435	1,500	1,550	50
Overhead Allocation	500	500	-	500	500	-
AFUDC	-	82	82	-	100	100
Tax	(428)	(682)	(254)	(530)	(543)	(13)
	1,073	2,530	1,458	1,470	13,357	11,887

2.4.1 THERMAL ENERGY SERVICES - DIRECT COSTS

The direct costs include feasibility assessment, design, equipment and construction of the various thermal energy solutions. These costs vary with the number, nature and development stage of projects. As such, an approved spending amount was not specified for 2010 and 2011 and a variance is therefore not reported. The increase in 2011 over 2010 is attributable to increased market interest in certain sectors such as schools and hospitals, with some projects beginning construction in 2011. These projects will be brought forward for BCUC approval in 2011.

2.4.2 THERMAL ENERGY SERVICES - SALES AND MARKETING O&M AND BUSINESS DEVELOPMENT

Sales and marketing O&M includes the labour of the 12 employees in Thermal Energy Services in 2011 as well as the direct labour charged through timesheets from individuals in other areas of the Companies. The costs also include contributions to industry associations of $15 thousand in 2011.[3] As agreed to in the NSA, these costs were budgeted at $1 million in 2010 and $1.5 million in 2011. As shown in Table G-2, the O&M and Business Development costs captured in the deferral account were $1.4 million in 2010 and are projected to be $1.6 million in 2011.

2.4.3 OVERHEAD ALLOCATION

In Commission Order G-141-09, FEI agreed to charge Alternative Energy Services customers $0.5 million for 2010 and $0.5 million for 2011 for administrative services provided by the gas utility to the alternative energy customers. As part of this application, FEI undertook a review of which services should be included in this administrative charge and what the charge should be for 2012 and 2013. Administrative services include those services not directly charged or chargeable and include the following categories:

- Executive: time to review current status of projects, monitor status of projects and reviewing and approving potential projects.

[3] Contributions of $5 thousand to The Canadian District Energy Association, The Community Energy Association and Geoexchange BC for a total of $15 thousand in 2011.

- Finance: management and financial reporting and accounts payable.
- Regulatory affairs: reviewing cost of service models, tariffs and project management
- Human Resources: recruiting and compensation and benefits.
- Information technology: IT support to existing employees charging time directly to the Thermal Energy Services deferral.
- Facilities: allocation of facilities costs for employees charging directly into the Thermal Energy Services deferral account. The facilities include space in the Surrey Operations Centre, Garbally/Langford and the Burnaby facility.

Based on the review, FEI has estimated that a charge of $0.5 million for both 2012 and 2013 be included as a recovery of overheads for the benefit of FEI and its ratepayers. This charge represents the expected administrative costs of supporting the Thermal Energy Services businesses.

2.5 Mark to Market – Hedging Transactions

This deferral account was approved by Commission Order No. E-22-95 to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing. The balance at the end of 2010 was $115.6 million credit.

2.6 Mark to Market – Customer Care Enhancement Project

This deferral account was approved by Commission Order No. G-96-10 to record mark-to-market adjustments due to fluctuations in rates on the foreign currency exchange forward contract for the CCE Project. The balance at the end of 2010 was $189.7 thousand debit.

2.7 Non Rate Base Deferrals Entering Rate Base in 2012

The following is a list of all of the non rate base deferral accounts that will be entering rate base in 2012. A discussion of each of these accounts is included in Section 6.3.

a) Tilbury Property Purchase (Land Retained)[4]
b) CCE Project Deferred O&M and Cost of Service (with allocation to Vancouver Island and Whistler)
c) Kootenay River Cost of Service
d) 2010-2011 Biomethane Program Costs
e) 2011 CNG and LNG Service Costs and Recoveries

[4] This account transfers to rate base through the appropriate Land account and is included in gross plant in 2012 as shown in Section 7, Tab 7.1, Schedule 46, Column 3, row 29

f) Residual Deferral - Rider 2 ROE Revenue Requirement Volume Variance

g) Residual Deferral – Rider 4 Delivery Refund Rider Volume Variance

h) Residual Deferral – Rider 4 Lochburn Land Costs Volume Variance

3 VANCOUVER ISLAND

3.1 Rate Stabilization Deferral Account

At the end of 2010, the balance in the Rate Stabilization Deferral Account ("RSDA") was $35.618 million. Commission Order No. G-140-09 approved the creation of the RSDA. to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding O&M variances from forecast, with the balance in the RSDA being amortized into cost of service after 2011 to offset future rate increases. Further discussion of the treatment of this account for 2012 and 2013 is included in Section 3.

3.2 Mark to Market – Hedging Transactions

This deferral account was approved by Commission Order No. E-22-95, to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing. The balance at the end of 2010 was $46 million credit.

3.3 Mark to Market - LNG Facility

This deferral account was approved by Commission Order No. C-9-07 to record currency exchange differences for the Mt Hayes LNG Project for an amount of contracted US dollar purchases expected to be $50 million USD. The balance at the end of 2010 was $48.8 thousand credit.

Appendix H
ORGANIZATION CHARTS

1 ORGANIZATION CHARTS

This appendix includes the Organization Charts for FEU as at December 31, 2011, reflecting the current organization stru cture. Consistent with Section 5 of the Application, the ch arts reflect annual FTEs as at December 31, 2011.

The charts in this appendix are organized as follows:

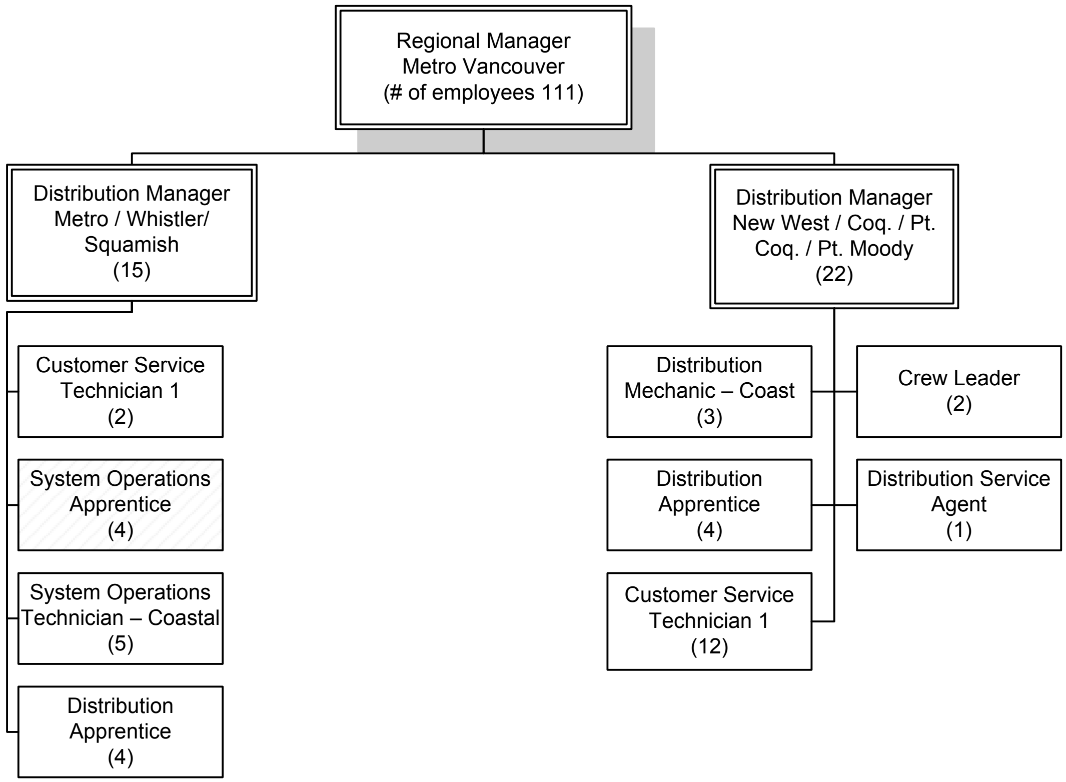
1. Operations (Natural Gas) (Distribution and Transmission)
2. Energy Supply & Resource Development
3. Customer Service
4. Energy Solution & External Relations
5. Information Technology
6. Business Services (Operations Engineering and Operations Support)
7. Facilit ies
8. Human Resources
9. Environmental Heatlh & Safety
10. Finance and Regulatory

FortisBC Energy Inc.

As at December 31, 2011

- **Vice President Operations (Natural Gas)**
  Total # of employees 744
  (FEI 626)
  (FEVI 113)
  (FEW 2)
  (Ft. Nelson 3)
  - Executive Assistant (1)
  - Regional Manager Fraser Valley (111)
  - Regional Manager Metro Vancouver (113) includes FEW 2
  - Regional Manager Interior North (63) includes Ft. Nelson 3
  - Regional Manager Interior South (80)
  - Director Asset Management (15)
  - Manager Business Performance (4)
  - Director Operations Centre (193) 180 FEI 13 FEVI
  - General Manager Transmission Operations (86) 55 FEI 31 FEVI
  - Regional Manager Vancouver Island (69) FEVI

FortisBC Energy Inc.
Distribution
As at December 31, 2011



FortisBC Energy Inc.

Distribution

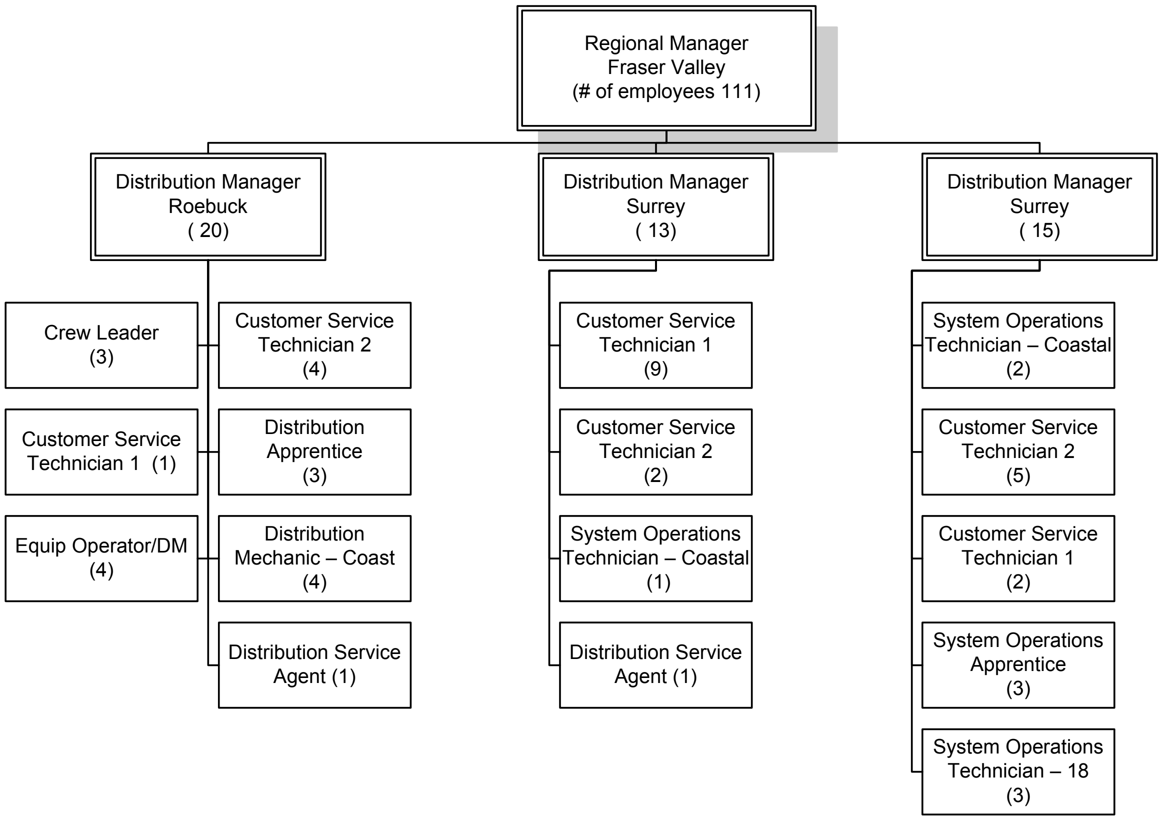
As at December 31, 2011

- Regional Manager Metro Vancouver
  - Distribution Manager Richmond (21)
    - Customer Service Technician 1 (7)
    - Customer Service Technician 2 (2)
    - Crew Leader (2)
    - Distribution Mechanic - Coast (2)
    - Distribution Apprentice (4)
    - Distribution Service Agent (1)
    - Clean-up Truck Driver (1)
    - Equip Operator/ DM (1)
    - Equipment Operator 1 (1)
  - Distribution Manager Vancouver (25)
    - Distribution Apprentice (8)
    - Crew Leader (3)
    - Distribution Mechanic – Coast (4)
    - Equip Operator/ DM (1)
    - Distribution Service Agent (1)
    - Equipment Operator 1 (1)
    - Customer Service Technician 1 (3)
    - Customer Service Technician 2 (4)
  - Distribution Manager North Shore / Burnaby (23)
    - Equipment Operator 1 (1)
    - Distribution Apprentice (8)
    - Customer Service Technician 1 (4)
    - Distribution Mechanic – Coast (4)
    - Crew Leader (3)
    - Customer Service Technician 2 (2)
    - Distribution Service Agent (1)

FortisBC Energy Inc.

Distribution

As at December 31, 2011



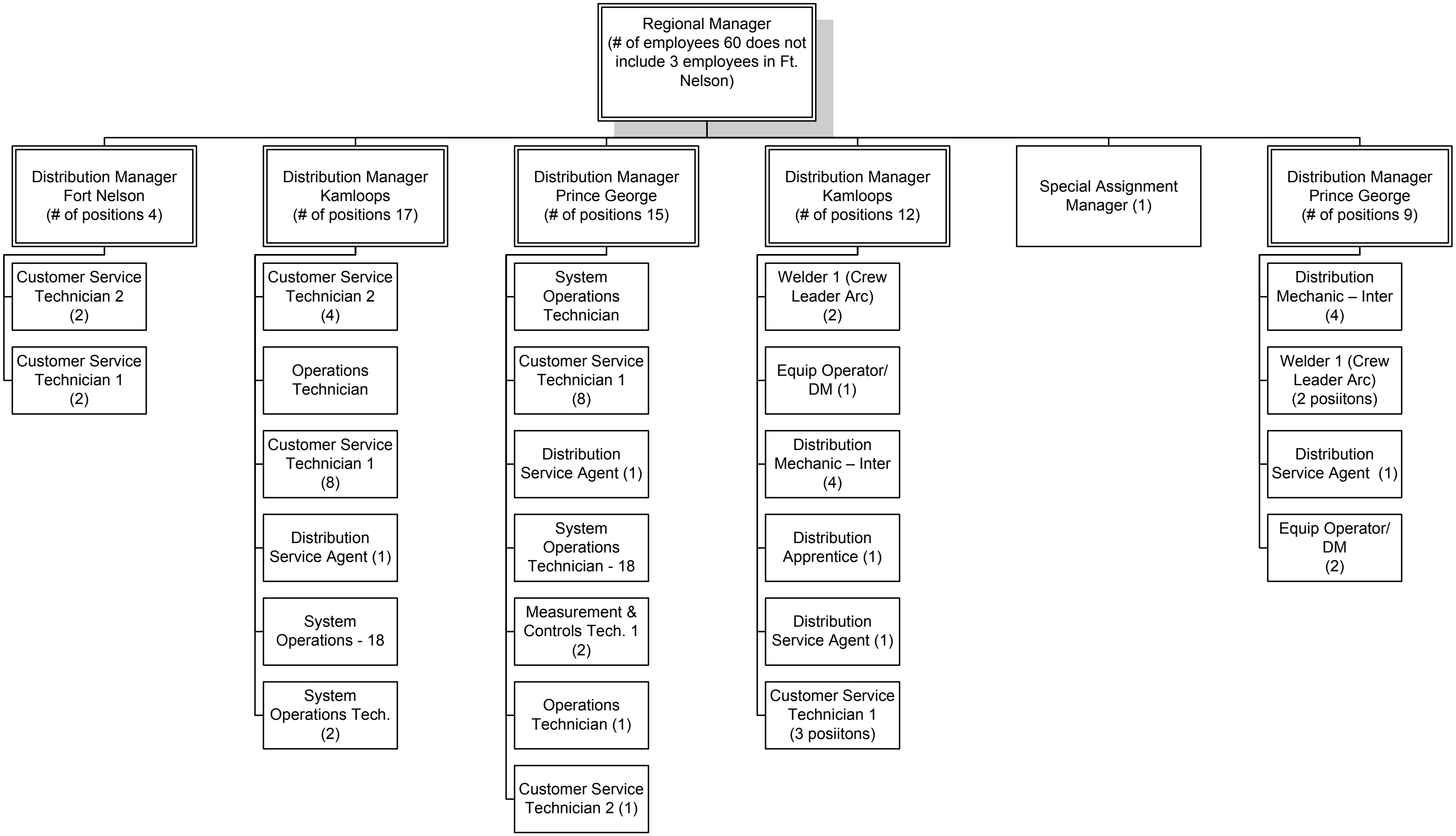
FortisBC Energy Inc.
Distribution
As at December 31, 2011

- Regional Manager, Fraser Valley
  - Distribution Manager Langley (# of positions 22)
    - Distribution Apprentice (6)
    - Distribution Service Agent
    - Distribution Mechanic – Coast (8)
    - Equipment Operator 1 (1)
    - Crew Leader (3)
    - Equip Operator/DM (3)
  - Distribution Manager Abbotsford (# of positions 19)
    - Crew Leader (4)
    - Distribution Service Agent (1)
    - Customer Service Technician 1 (3)
    - Paving Foreman (2)
    - Distribution Apprentice (3)
    - Distribution Mechanic – Coast (2)
    - Equip Operator/DM (2)
    - Equipment Operator 1 (2)
  - Distribution Manager Albion (# of positions16)
    - Crew Leader (2)
    - Customer Service Technician 1 (6)
    - Equipment Operator 1 (1)
    - Distribution Mechanic – Coast (2)
    - Distribution Apprentice (3)
    - Equipment Operator/ DM (2)

FortisBC Energy Inc.

Distribution

As at December 31, 2011



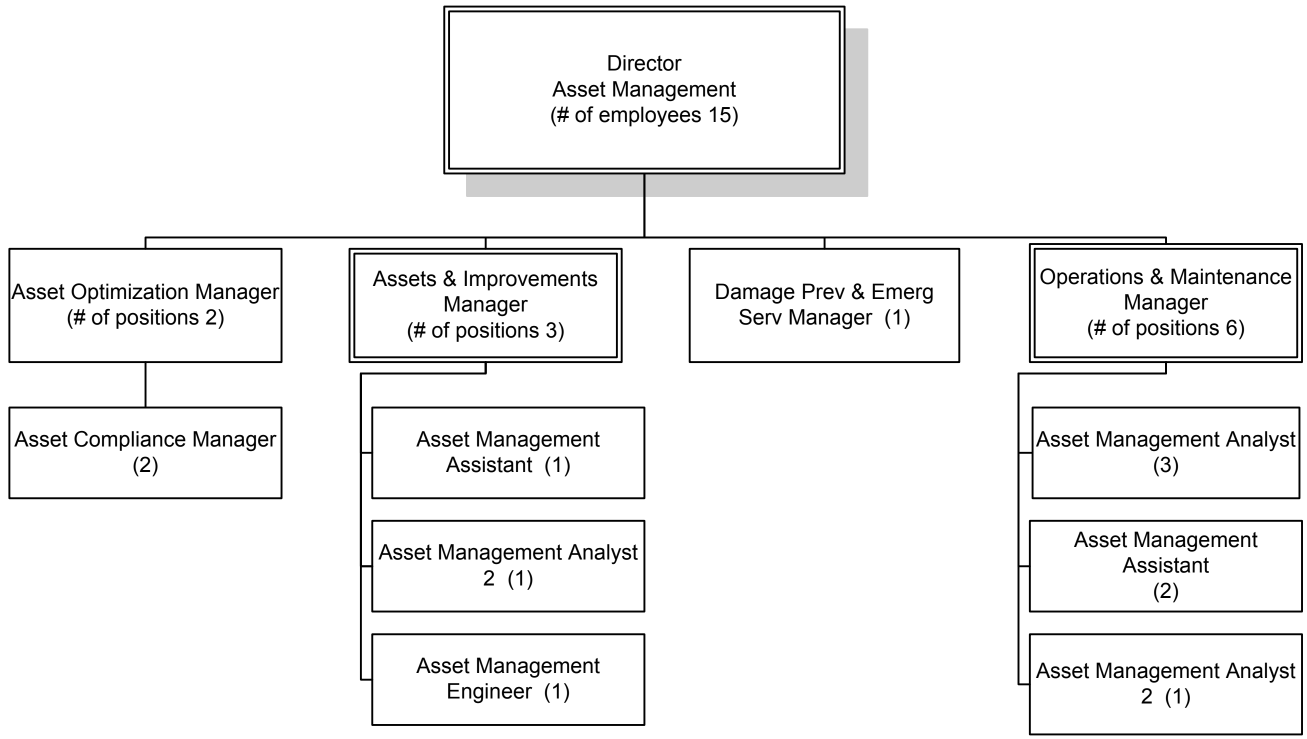
FortisBC Energy Inc.
Distribution
As at December 31, 2011

- Regional Manager Interior South (# of employees 80)
  - Distribution Manager Vernon (# of positions 13)
    - Equip Operator/ DM (2)
    - Distribution Mechanic – Inter (1)
    - Distribution Service Agent (1)
    - System Operations Technician (1)
    - Crew Leader (1)
    - Customer Service Technician 1 (4 posiitons)
    - Distribution Apprentice (2)
    - Welder 1 (Crew Leader Arc (1)
  - Distribution Manager Kelowna (# of positions 10)
    - Welder 1 (Crew Leader Arc(
    - Distribution Apprentice (2)
    - Crew Leader
    - Equip Operator/ DM (3)
    - Distribution Service Agent (1)
    - Distribution Mechanic (1)
  - Distribution Manager Kelowna (# of positions 11)
    - Distribution Service Agent
    - Customer Service Technician 1 (3)
    - Customer Service Technician 2 (5)
    - System Operations Technician (1)
    - System Operations Technician - 18
  - Distribution Manager Cranbrook (# of positions 14)
    - Distribution Service Agent (1)
    - Distribution Mechanic (1)
    - Customer Service Technician 1 (4)
    - Welder 1 (Crew Leader Arc((2)
    - System Operations Technician (1)
    - Customer Service Technician 2 (2)
    - Distribution Apprentice (2)
    - Measurement Control Tech. 1 (1)
  - Distribution Manager Trail (# of positions 14)
    - Equip Operator/ DM (2)
    - Sr Sales & Service Technician (1)
    - System Opns Tech. – 18 (2)
    - Distribution Service Agent (1)
    - Customer Service Technician 1 (4)
    - Welder 1 (Crew Leader Arc (1)
    - Distribution Apprentice (2)
    - Crew Leader (1)
  - Distribution Manager Penticton # of positions12)
    - Distribution Apprentice (2)
    - System Operations Technician
    - Welder 1 (Crew Leader Arc((2)
    - Customer Service Technician 1 (5)
    - Distribution Service Agent
    - Equip Operator/ DM

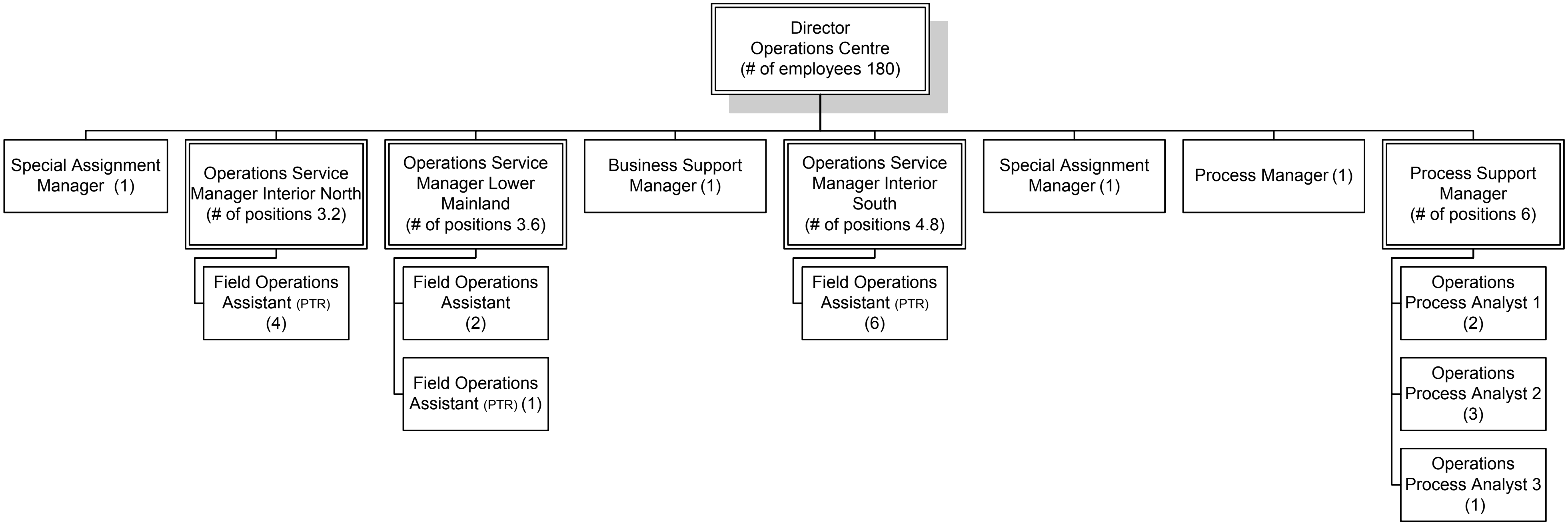
FortisBC Energy Inc.

Distribution

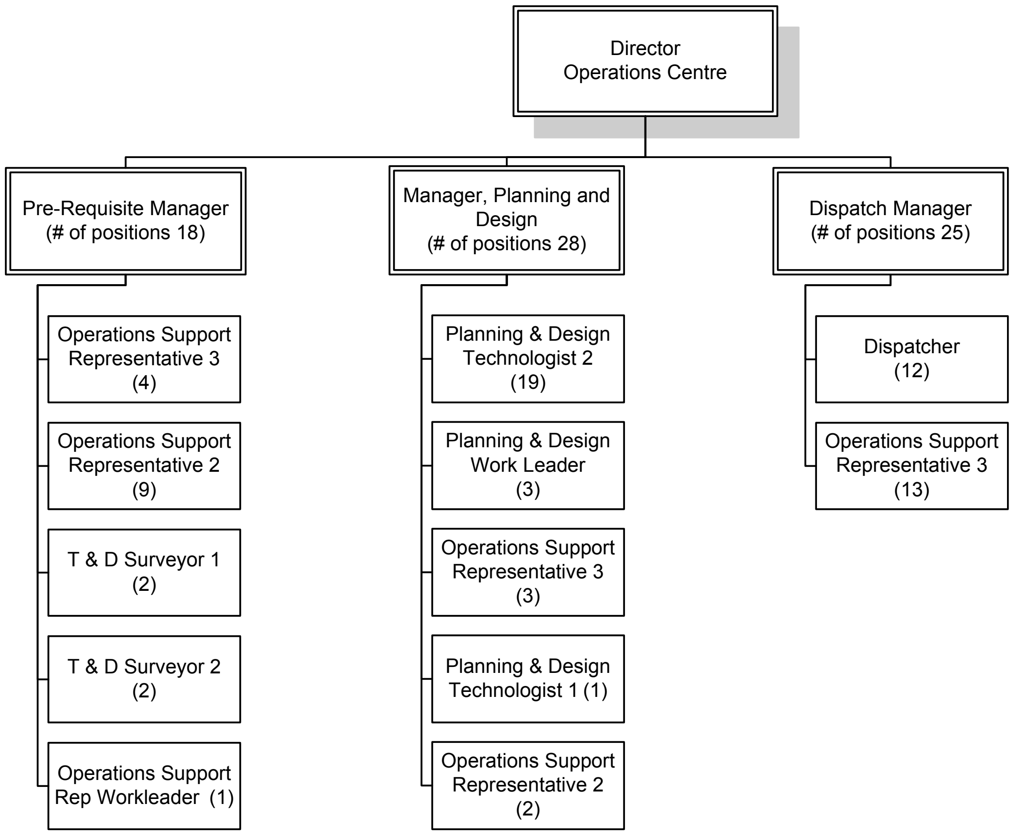
As at December 31, 2011



FortisBC Energy Inc.
Distribution
As at December 31, 2011



FortisBC Energy Inc.
Distribution
As at December 31, 2011



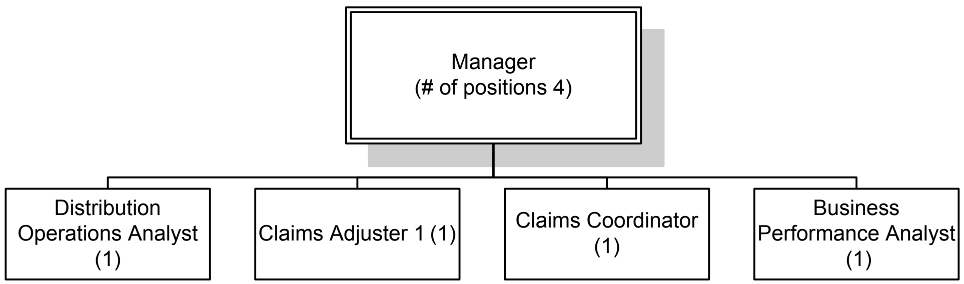
FortisBC Energy Inc.

Distribution

As at December 31, 2011

- Director Operations Centre
  - Emergency Support Manager (# of positions 8)
    - Emergency & Operations Representative (8)
  - Resource Planning Manager (# of positions 12)
    - Resource Management Co-ordinator (7)
    - Operations Support Representative 1 (4)
    - Operations Support Representative 1 PTR (2)
  - Manager, Install Centre (# of positions 38
    - Planning & Design Technician (17)
    - Planning & Design Technologist 1 (9)
    - Planning & Design Workleader (2)
    - Planning & Design Technologist 2 (9)
    - Operations Support Representative 3 (1)
  - Closing & System Survey Mgr (M&E Relief) (# of positions 18)
    - OSR Workleader (1)
    - Operations Support Representative 3 (15 posiitons)
    - Operations Support Representative 3 PTR (2)
    - Operations Support Representative 2 (1)

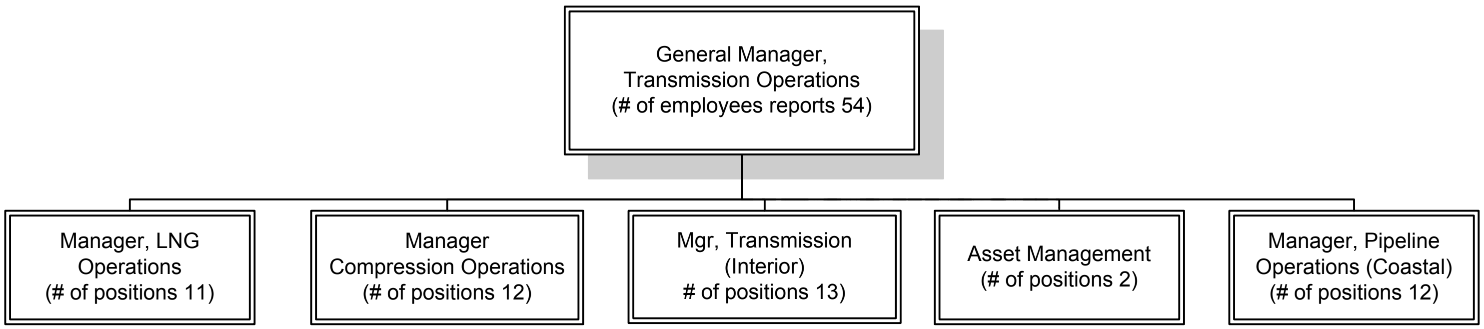
FortisBC Energy Inc.
Distribution
As at December 31, 2011



FortisBC Energy Inc.

TRANSMISSION

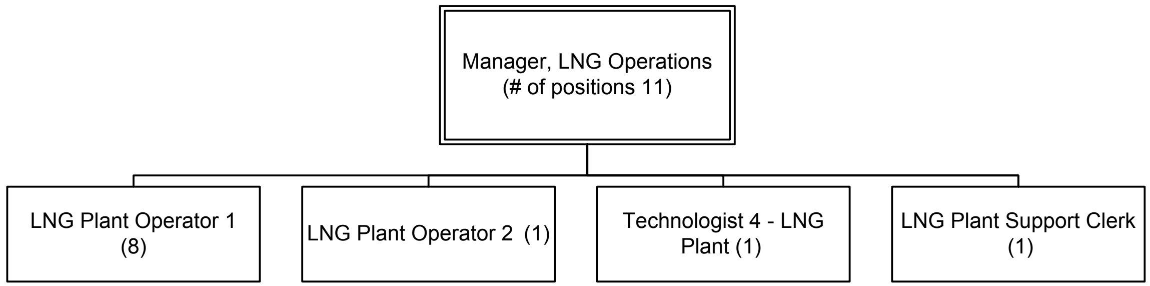
As at December 31, 2011



FortisBC Energy Inc.

TRANSMISSION

As at December 31, 2011



FortisBC Energy Inc.

TRANSMISSION

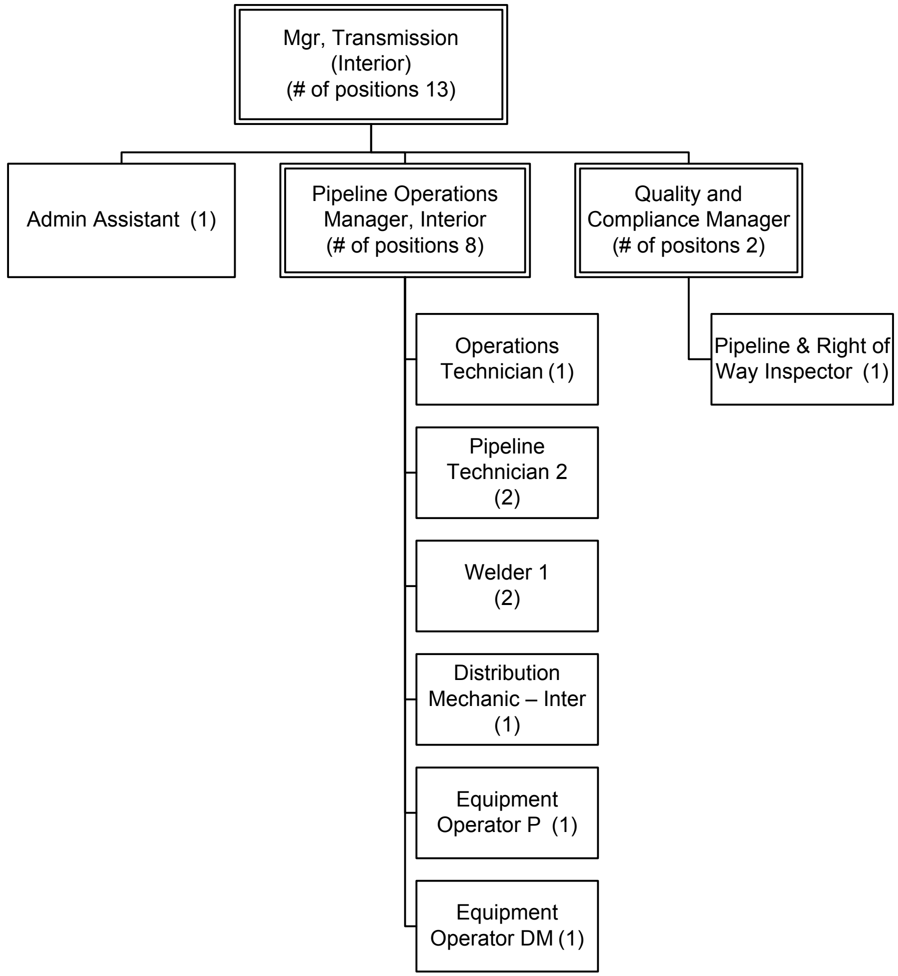
As at December 31, 2011

- Manager, Compression Operations (# of positions 12)
  - Work Leader (2)
  - Millwright (2)
  - Compression & Controls Technician 1 (7)
  - Admin Assistant, Transmission Ops (1)

FortisBC Energy Inc.

TRANSMISSION

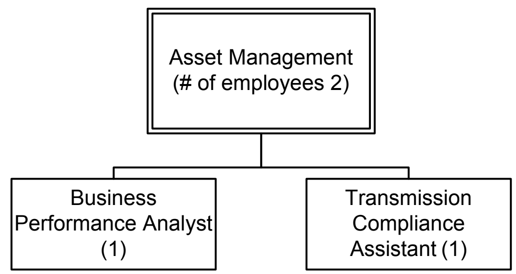
As at December 31, 2011



FortisBC Energy Inc.

TRANSMISSION

As at December 31, 2011



FortisBC Energy Inc.

TRANSMISSION

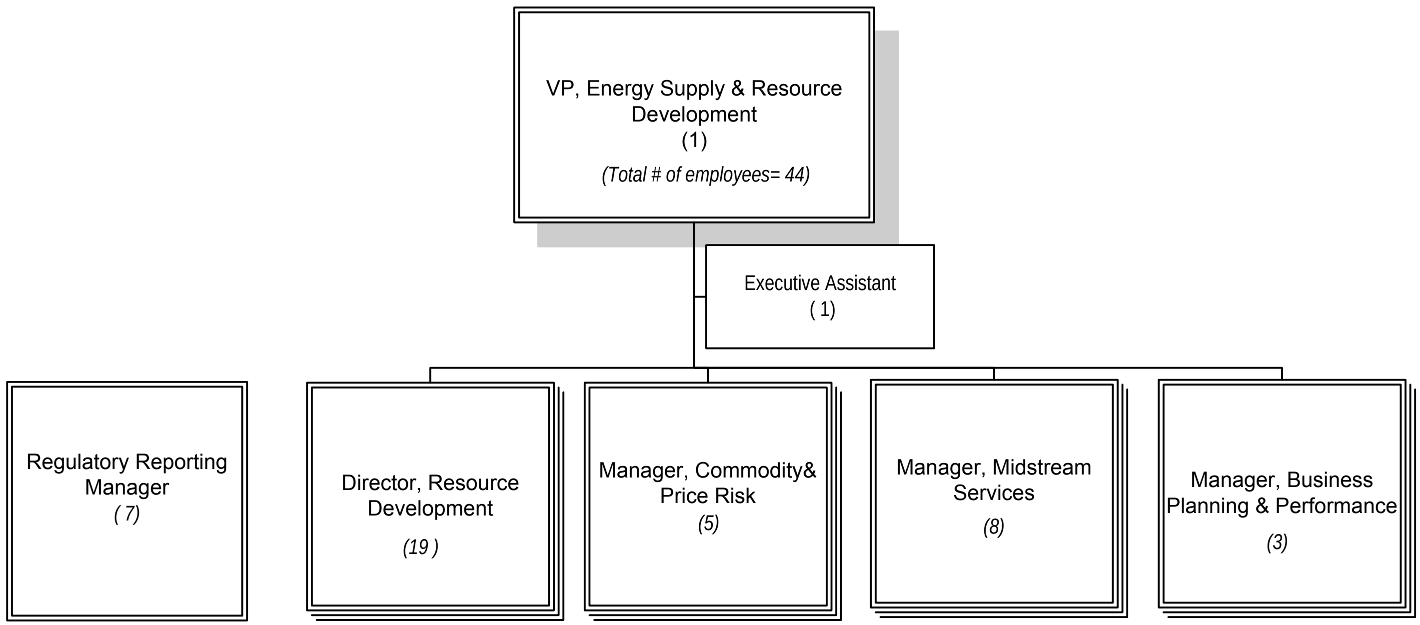
As at December 31, 2011

- Manager, Pipeline Operations (Coastal) (# of positions 12)
  - Pipeline & Right of Way Inspector Work Leader (1)
  - Distribution Mechanic – Coast (# of positions 5)
  - Pipeline & Right of Way Inspector (# of positions 3)
  - Crew Leader (# of positions 2)
  - Relief Manager (1)

FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

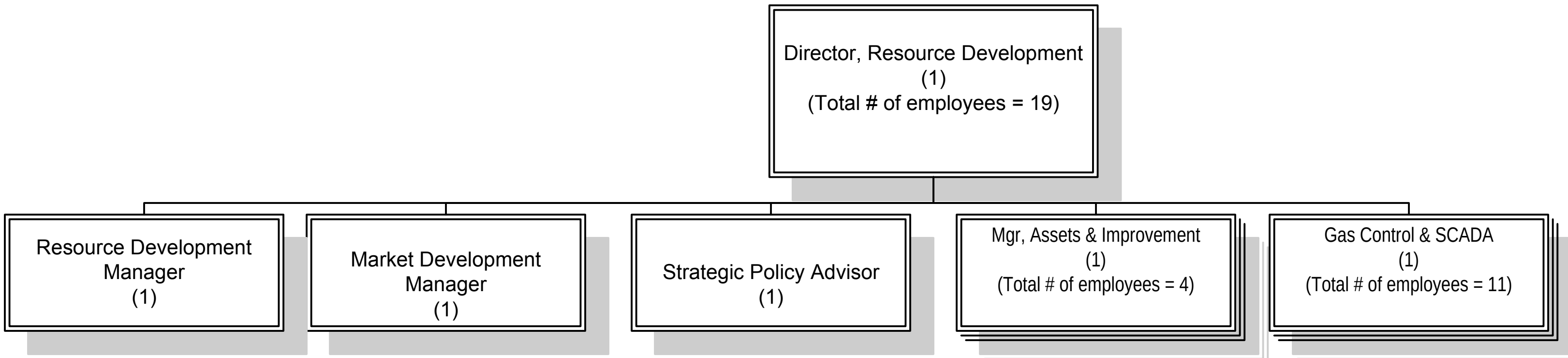
As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

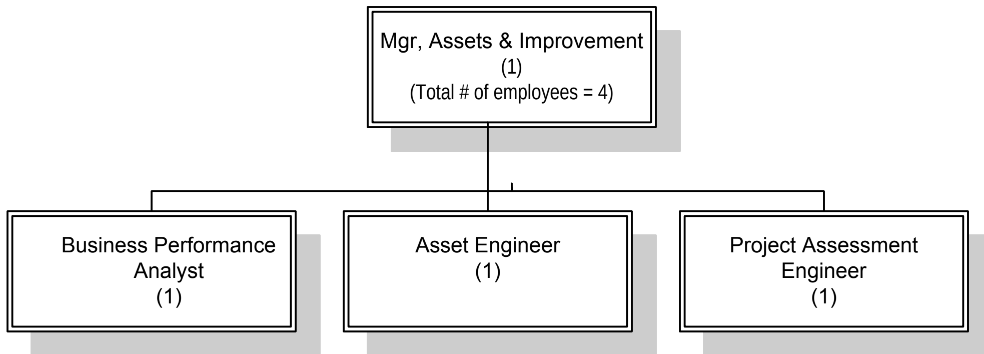
As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

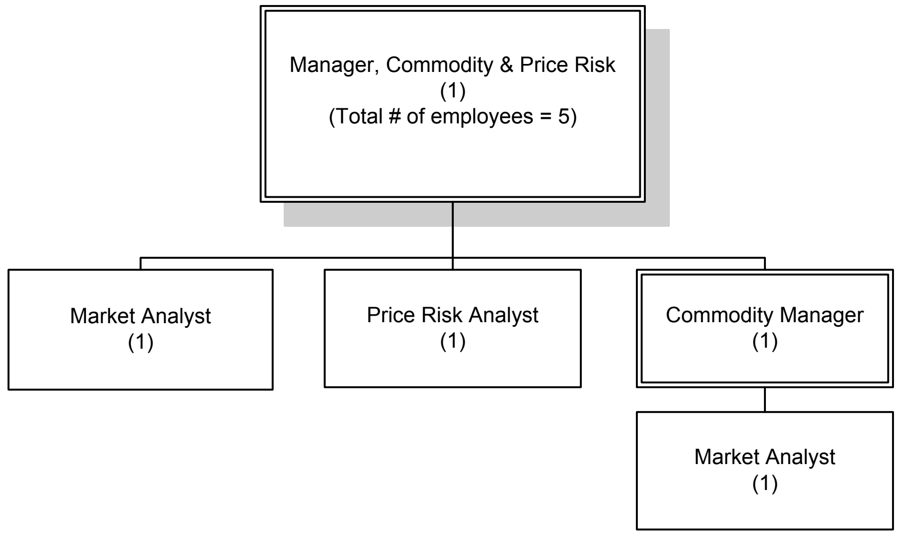
As OF December 31, 2011

- Gas Control & SCADA (1) (Total # of employees=11)
  - Gas Controller FTR (7)
  - Technologist 4 – SCADA (1)
  - Gas Control Coordinator (1)
  - Technologist 3 – SCADA (1)

FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

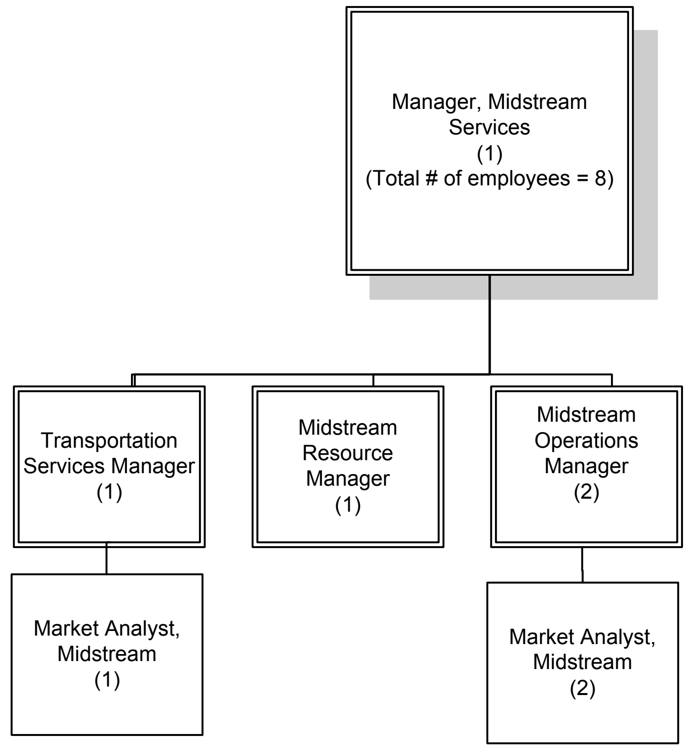
As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

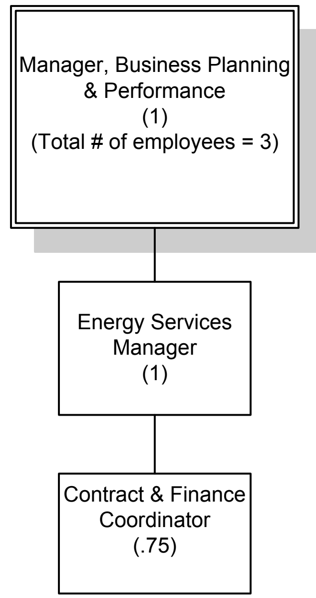
As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

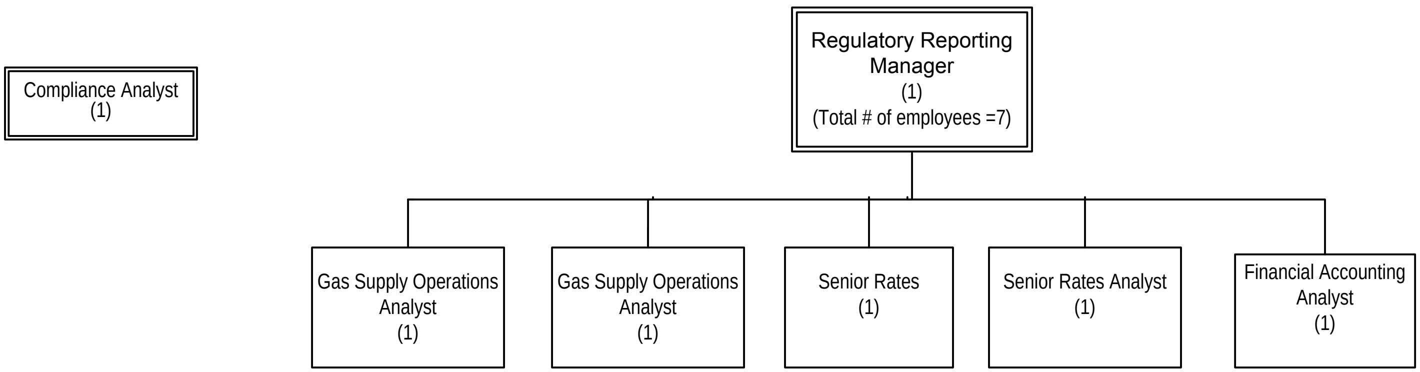
As OF December 31, 2011



FORTISBC ENERGY INC.

ENERGY SUPPLY & RESOURCE DEVELOPMENT

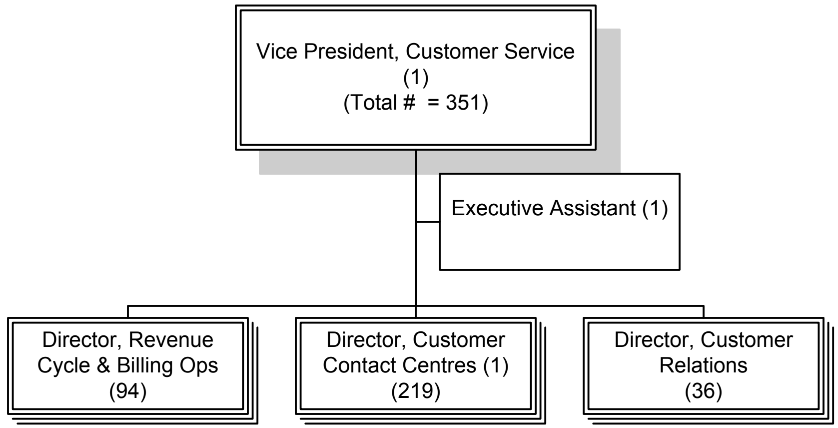
As OF December 31, 2011



FORTISBC ENERGY INC.

CUSTOMER SERVICE

As at December 31, 2011



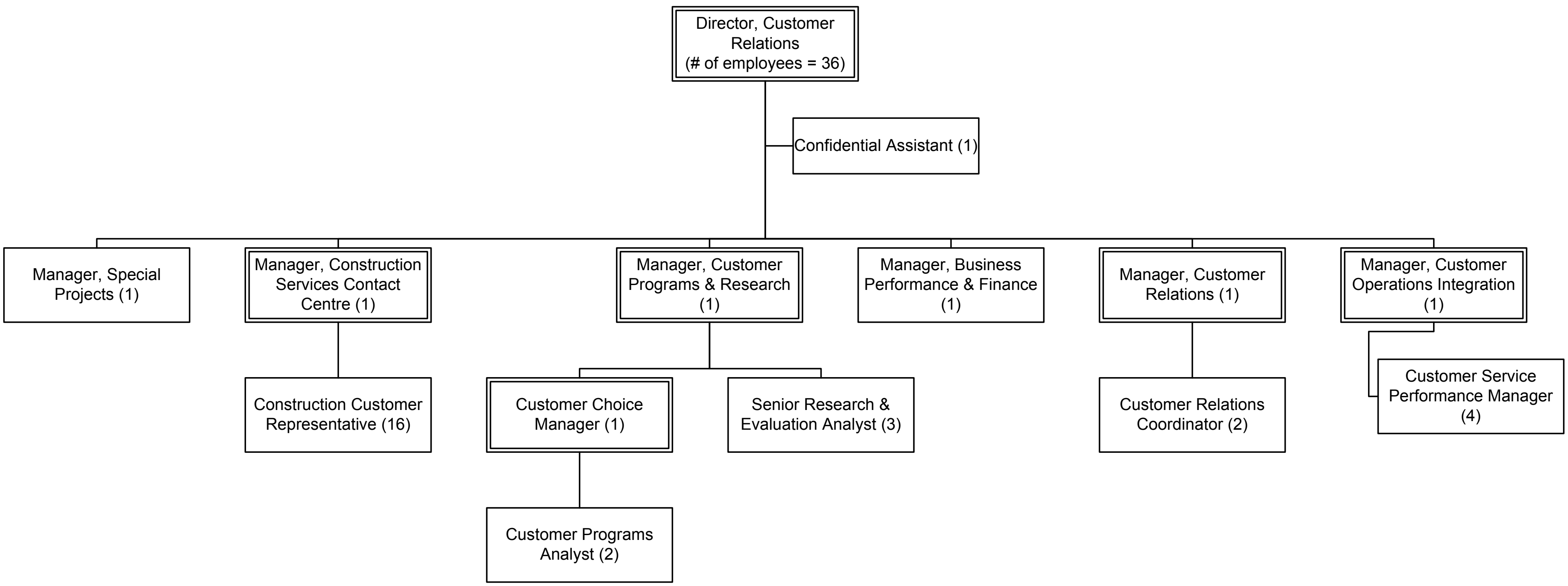
NOTE:

An increase in proficiency will result in fewer resources required by the end of the 2012 calendar year and as such the number of total FTE for the Customer Service department will decrease from 351 to 309 as at December 31st,2012.

FORTISBC ENERGY INC.

CUSTOMER SERVICE

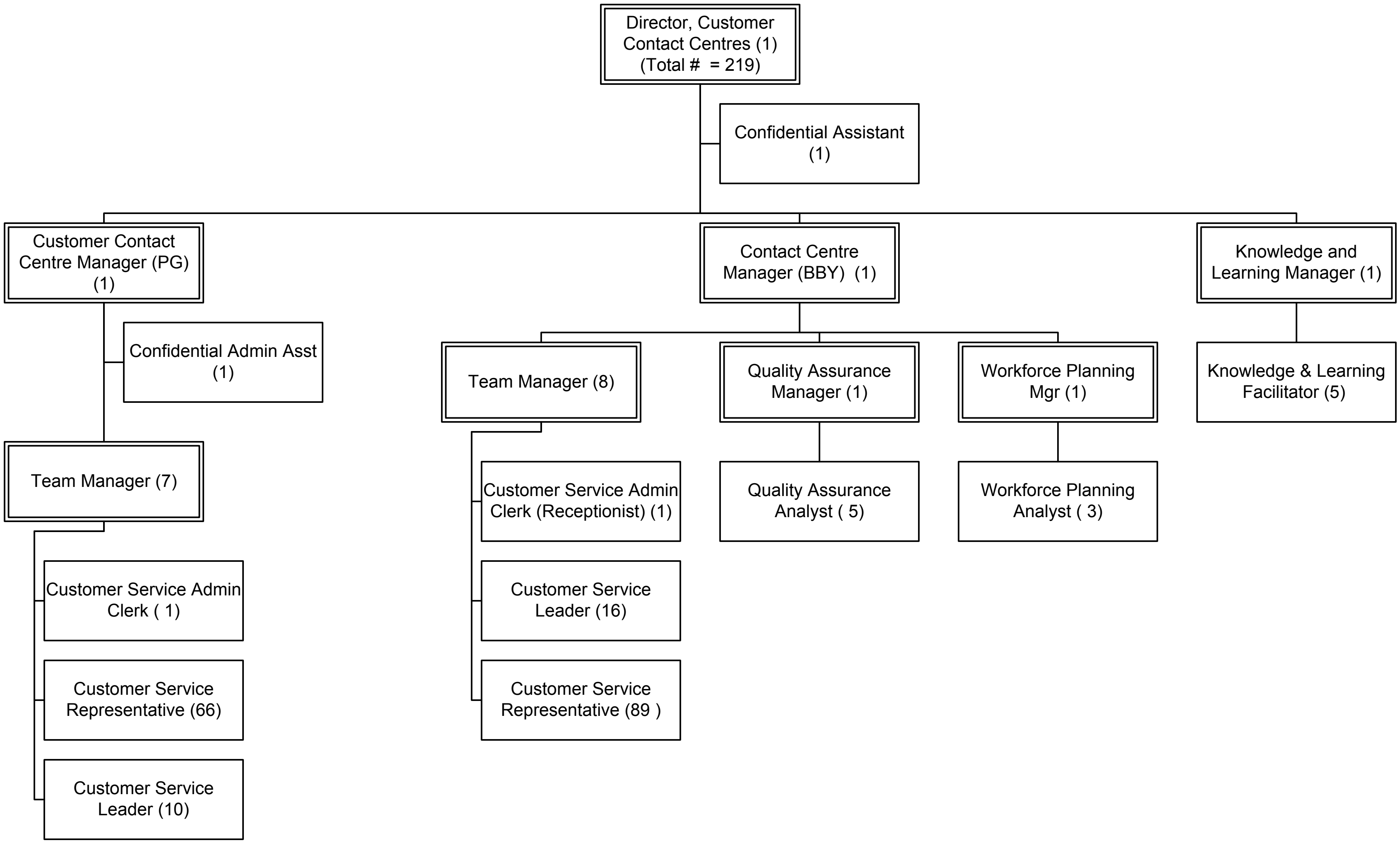
As at December 31, 2011



FORTISBC ENERGY INC.

CUSTOMER SERVICE

As at December 31, 2011



NOTE: These positions are shown as FTE and include a mix of full-time, part-time and auxiliary positions

FORTISBC ENERGY INC.

CUSTOMER SERVICE

As at December 31, 2011

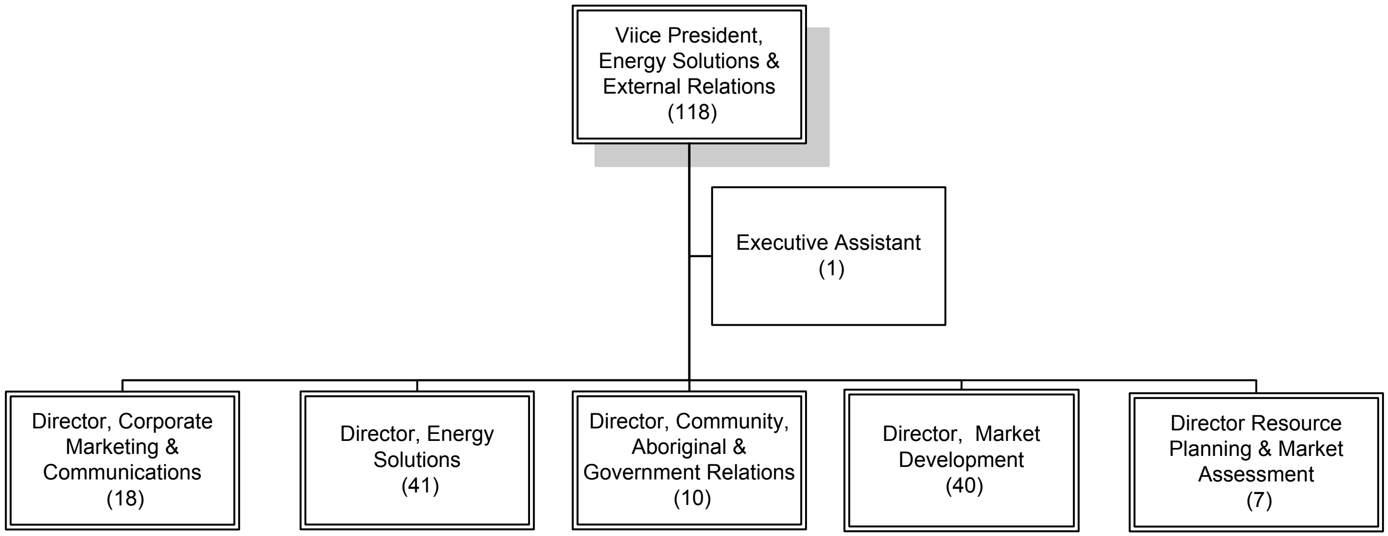
- Director, Revenue Cycle & Billing Ops (Total # = 94)
  - Manager, Billing Production (1)
    - Sr. Billing Analyst (BR3) (12)
    - Billing Leader (1)
    - Billing Exceptions Manager (1)
      - Billing Leader (1)
      - Sr. Billing Analyst (BR3) (8)
  - Manager, Billing Support (1)
    - Billing Assistant (BR1) (7)
    - Billing Analyst (BR2) (9)
    - Billing Leader (1)
    - MR Support Manager (1)
      - Meter Reader Coord (4)
  - Manager, Payments and Collections (1)
    - Billing Leader (1)
    - Billing Analyst (BR2) (8)
    - Collections Leader (1)
    - Collections Rep (10)
  - Industrial Billing Manager (1)
    - Industrial Billing Specialists (4)
  - Manager Complex Billing (1)
    - Sr. Billing Analyst (BR3) (8)
    - Complex Billing Leader (1)
    - Rates & Calculations Manager (1)
      - Complex Billing Leader (1)
      - Sr. Billing Analyst (BR3) (8)

NOTE: These positions are shown as FTE and include a mix of full-time and auxiliary positions

FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

As at December 31, 2011



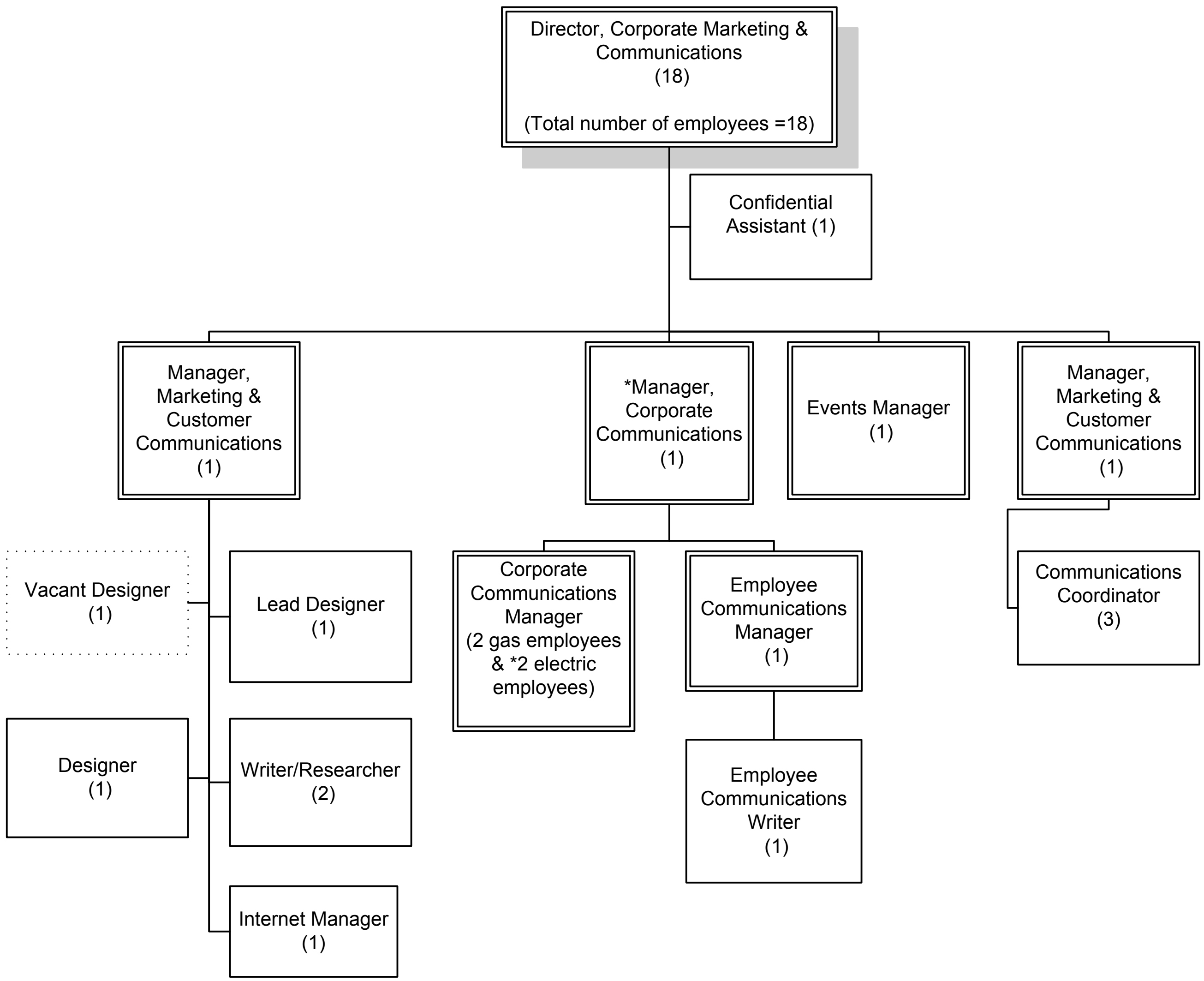
Note: All employees are FTR

TES Employees excluded from FTE & Headcount and organization chart roll up (not included in VP Direct Reports page 1). See page 5 for stand alone TES org chart.

FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

As at December 31, 2011

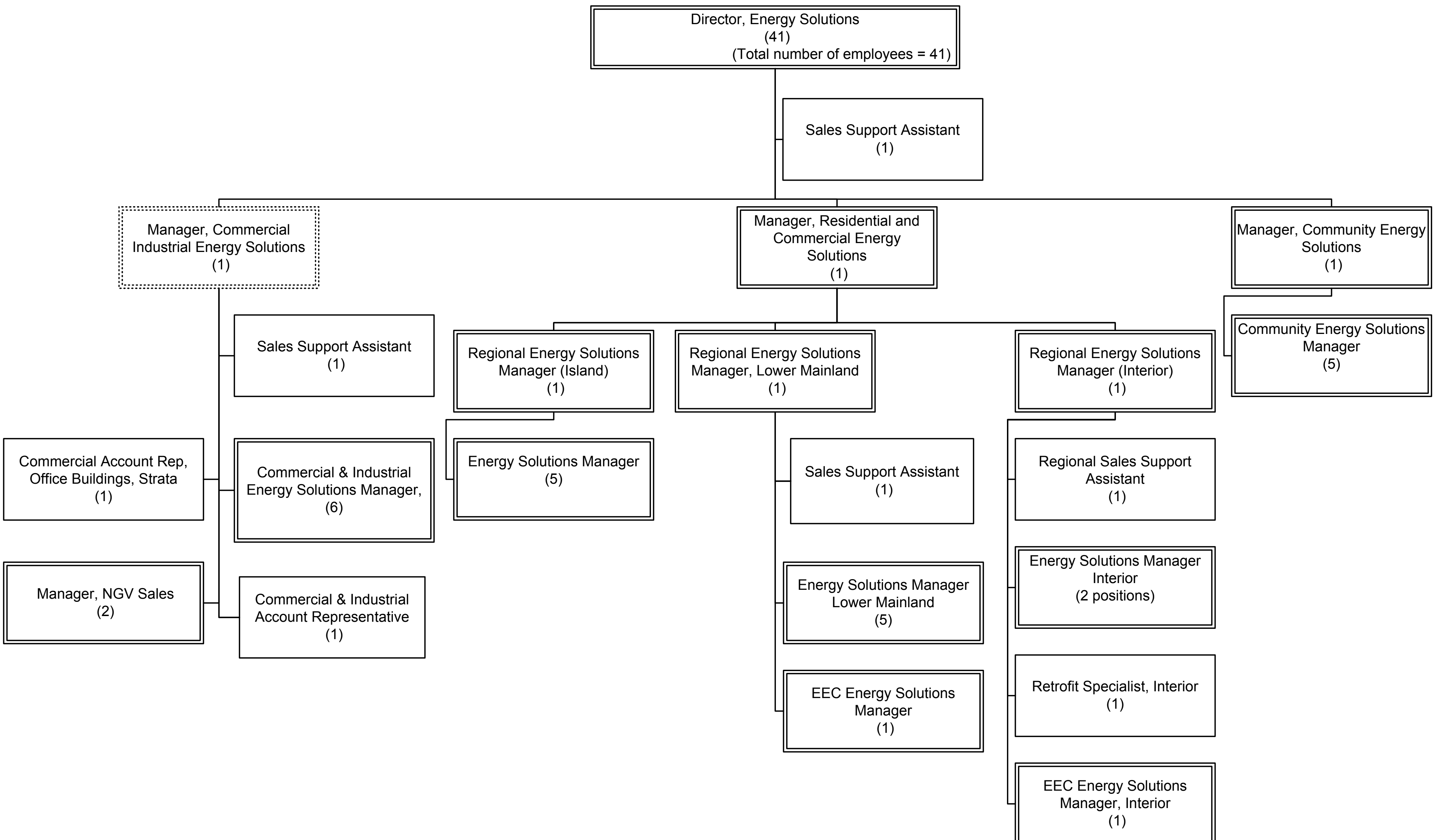


* Indicates “Electric Employees”

FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

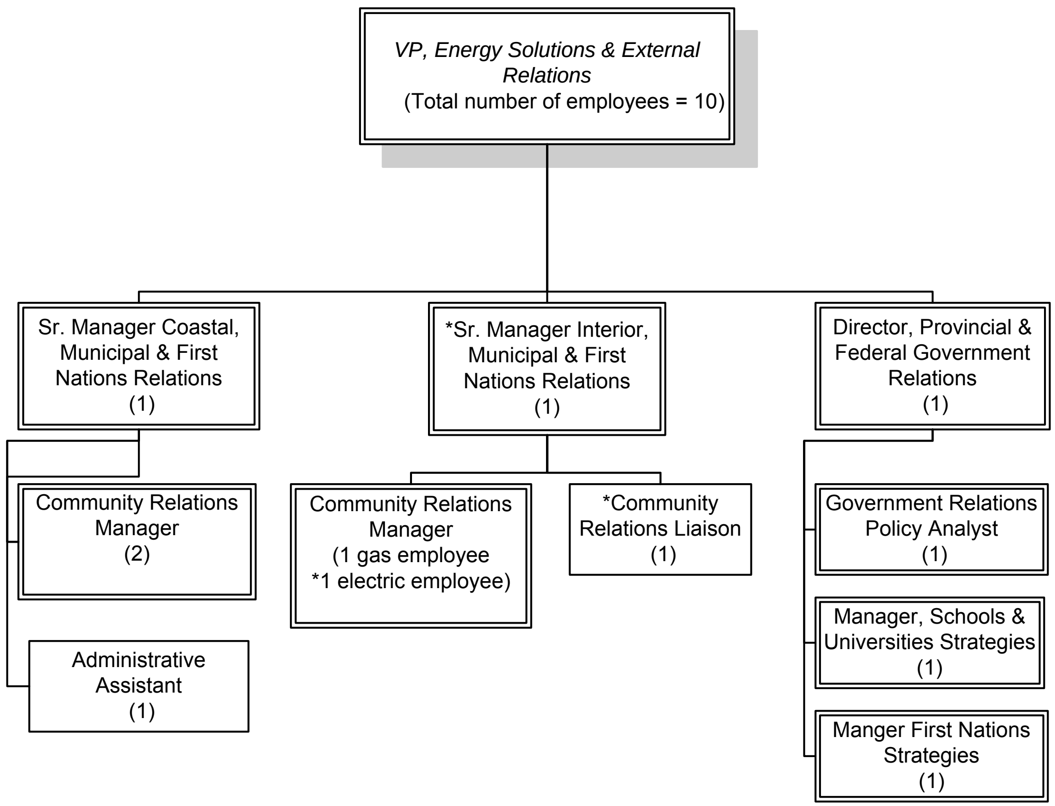
As at December 31, 2011



FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

As at December 31, 2011



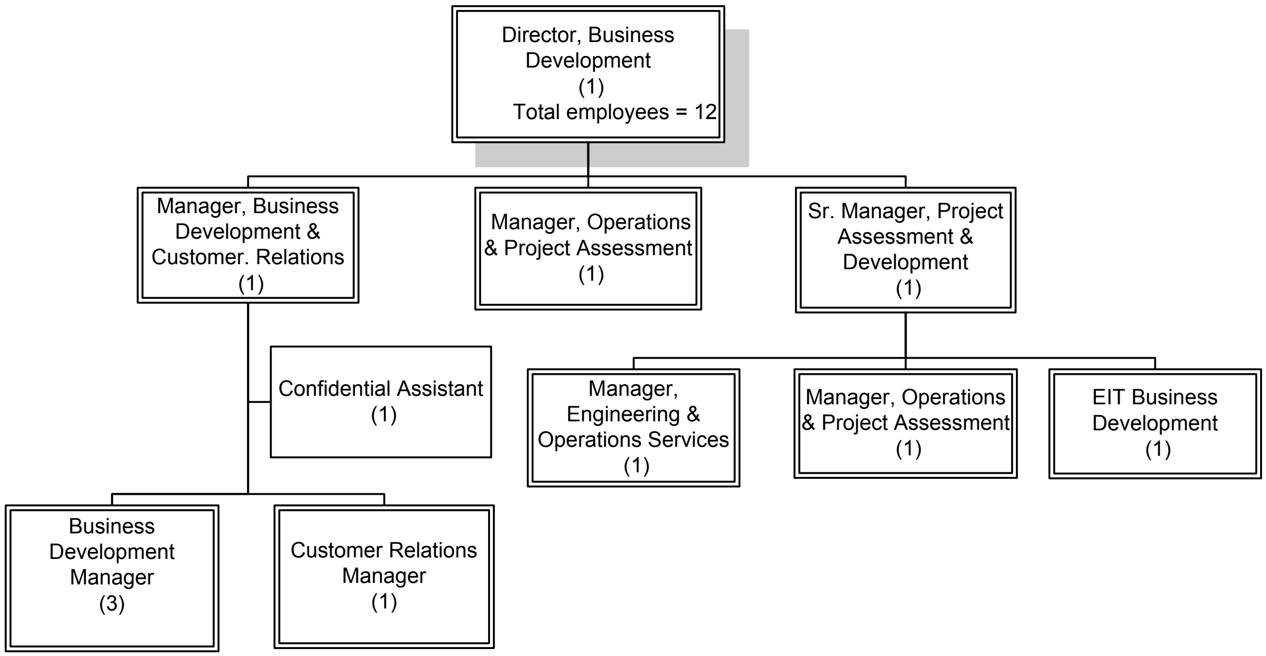
* Indicates “Electric Employees”

FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

As at December 31, 2011

THERMAL ENERGY SOLUTIONS

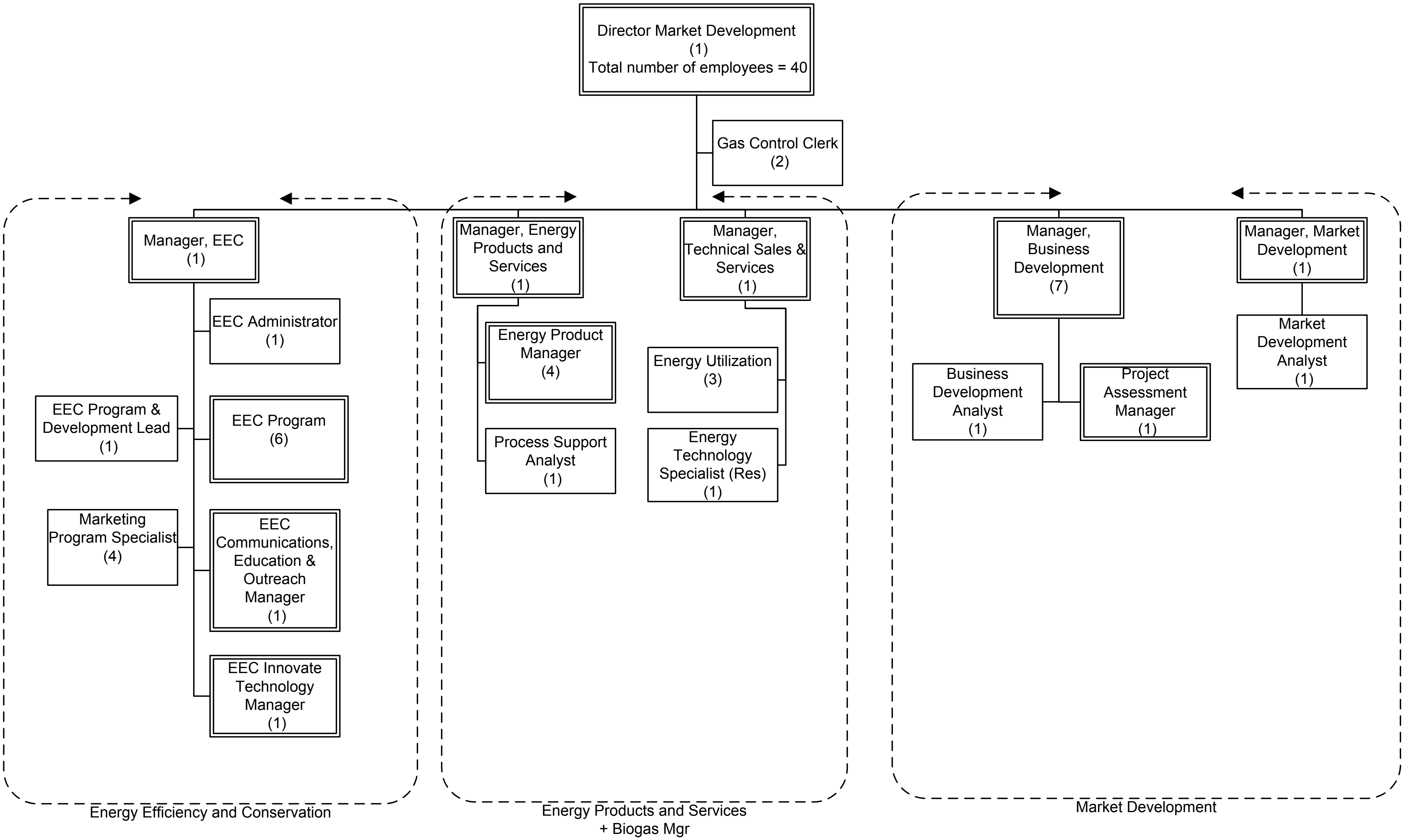


TES Employees excluded from FTE & Headcount and organization chart roll up (not included in VP Direct Reports page 1)

FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

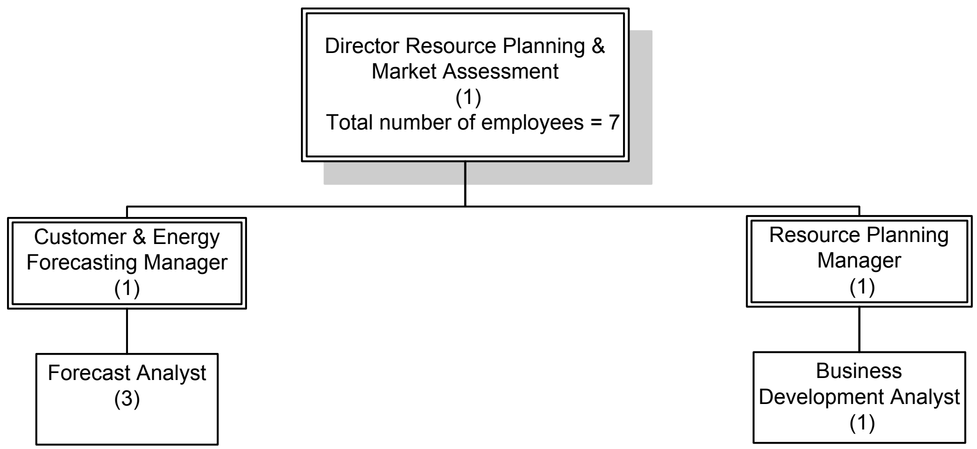
As at December 31, 2011



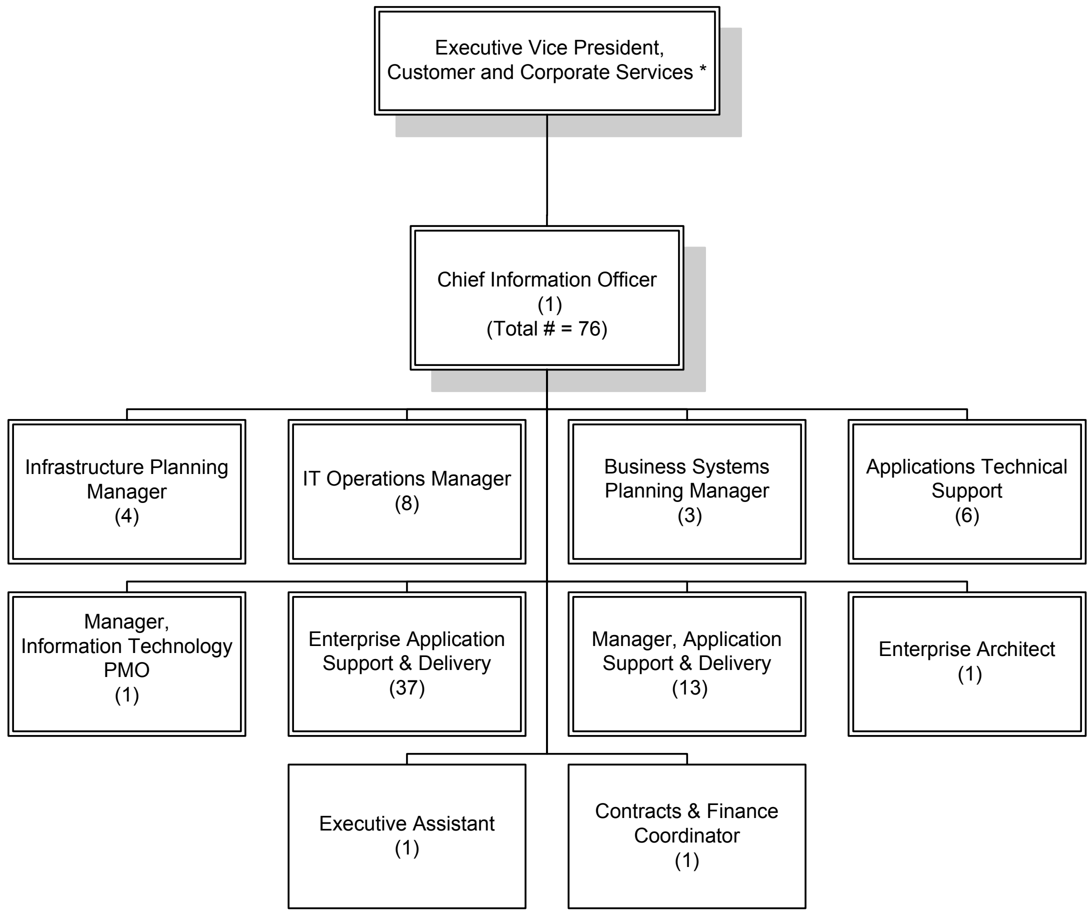
FORTISBC ENERGY INC.

ENERGY SOLUTIONS & EXTERNAL RELATIONS

As at December 31, 2011



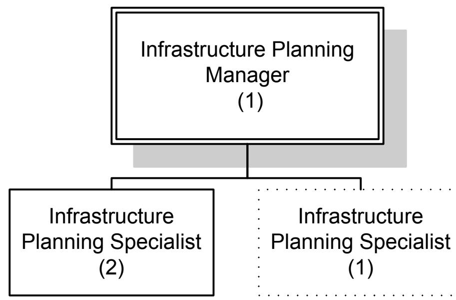
FortisBC Energy Inc
Information Technology
As at December 31, 2011



FortisBC Energy Inc

Information Technology

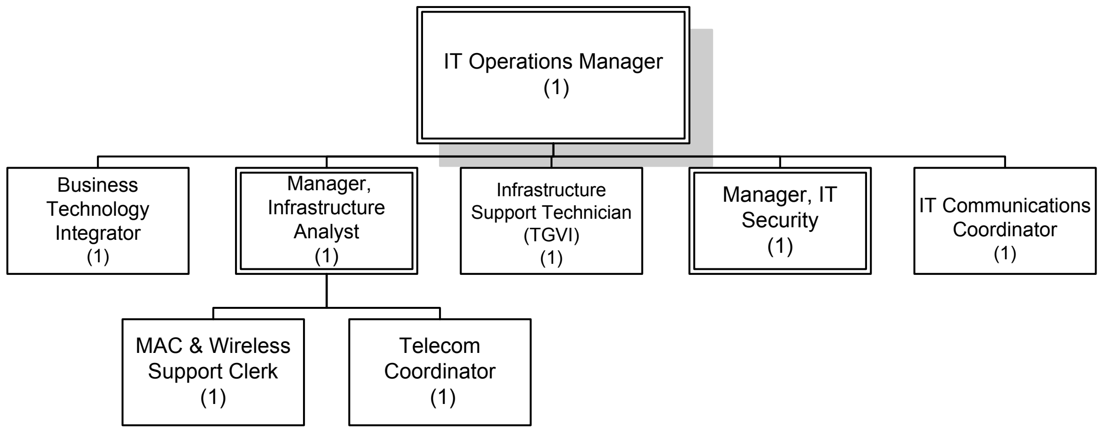
As at December 31, 2011



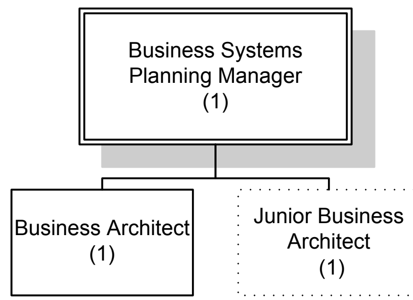
FortisBC Energy Inc

Information Technology

As at December 31, 2011



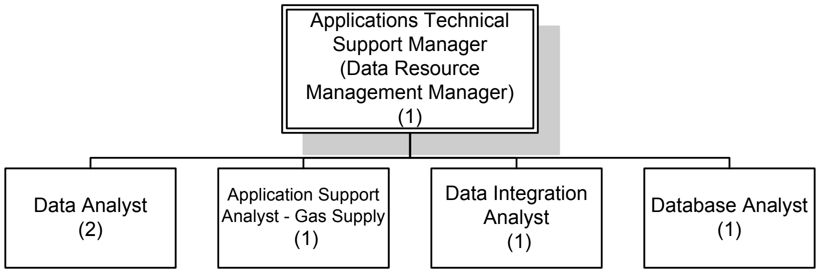
FortisBC Energy Inc
Information Technology
As at December 31, 2011



FortisBC Energy Inc

Information Technology

As at December 31, 2011



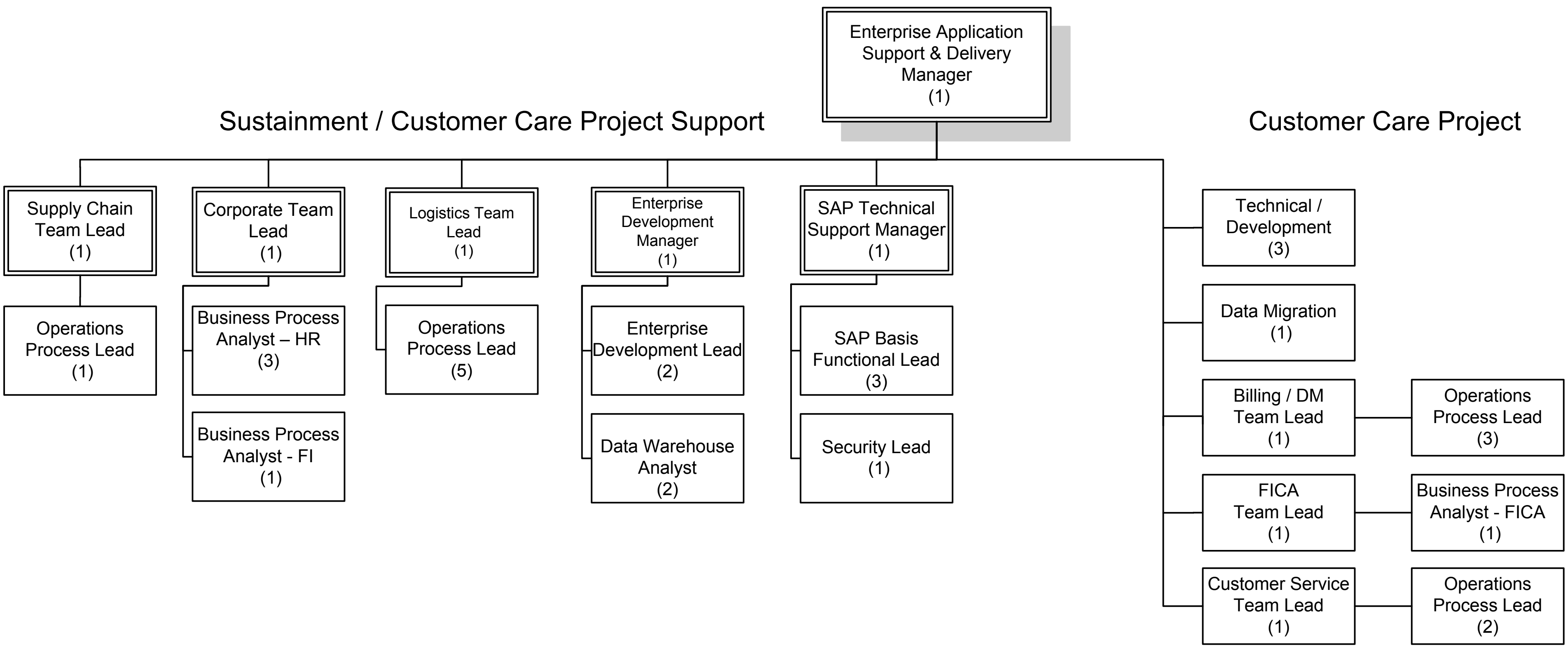
FortisBC Energy Inc

Information Technology

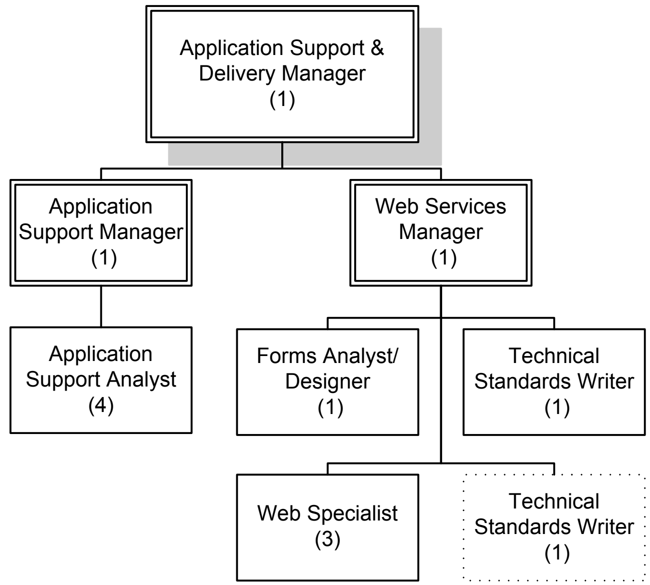
As at December 31, 2011

Manager,
Information Technology
PMO
(1)

FortisBC Energy Inc
Information Technology
As at December 31, 2011



FortisBC Energy Inc
Information Technology
As at December 31, 2011



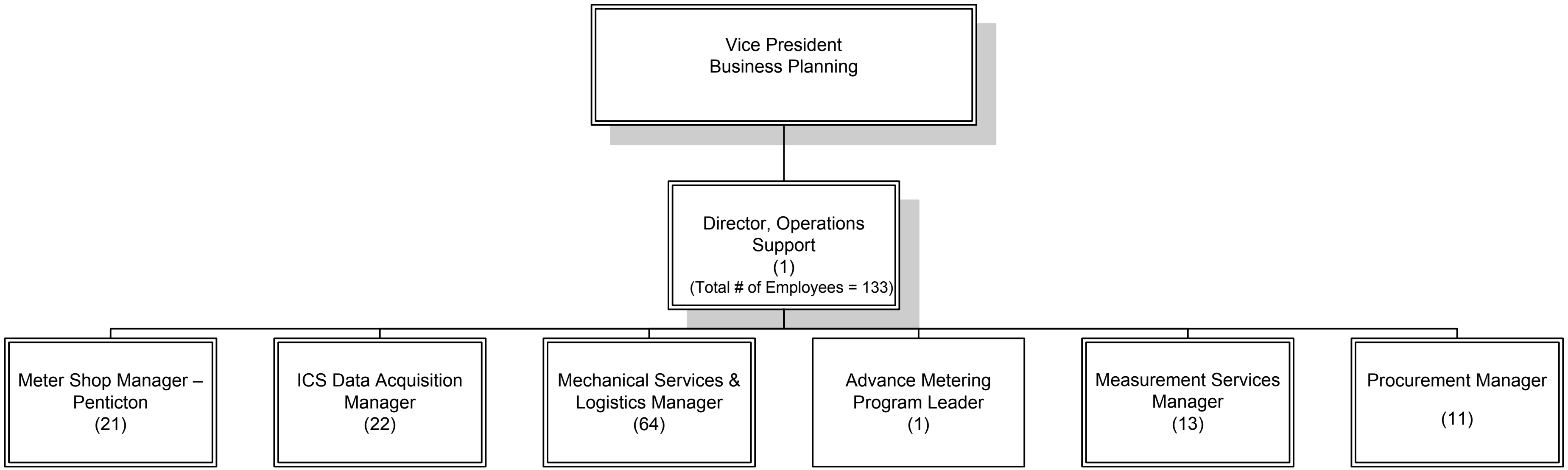
FortisBC Energy Inc

Information Technology

As at December 31, 2011

Enterprise Architect
(1)

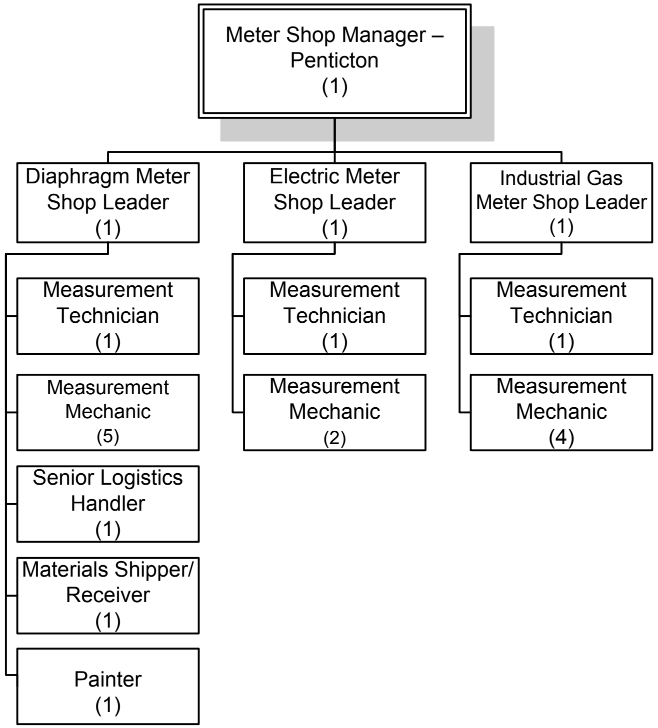
FortisBC Energy Inc
Business Services
As at December 31, 2011



FortisBC Energy Inc

Business Services

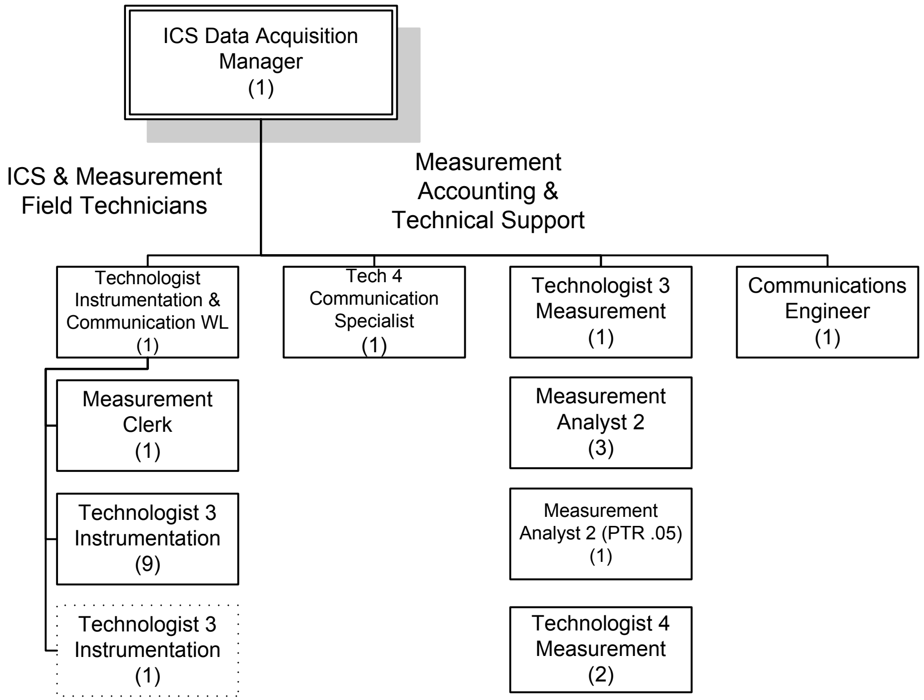
As at December 31, 2011



FortisBC Energy Inc

Business Services

As at December 31, 2011



FortisBC Energy Inc

Business Services

As at December 31, 2011

- Mechanical Services & Logistics Manager (1)
  - Mechanical Foreman- Welding (1)
    - Fitter Welder 1 (10)
    - Fitter Welder 1 (1)
    - Fitter Welder 2 (3)
    - Shop Mechanic 1 (1)
    - Shop Assistant (1)
  - Mechanical Foreman - Machine Shop (1)
    - Machinist Design (2)
    - Shop Mechanic 1 - Machine (4)
    - Shop Mechanic 1 - Machine (1)
    - Shop Mechanic 2 – Machine (1)
  - Mechanical Foreman- Prefab (1)
    - Shop Mechanic 1 - Prefab (6)
    - SOT (1)
    - Painter (1)
    - Shop Assistant (2)
  - Warehouse & Delivery Leader (1)
    - Yard Foreman (1)
    - Senior Logistics Leader (1)
    - Senior Logistics Leader (1)
    - Recycling Mechanic (1)
    - Material Shipper/ Receiver (1)
    - Material Shipper/ Receiver (3)
    - Material Truck & Trailer Operator (2)
    - Material Truck Driver (Coastal) (5)
    - Material Handler (Coastal) (6)
    - Material Handler (Coastal) 0.6
  - Inventory Analysts
    - Inventory Analyst 2 (2)
      - Inventory Analyst Relief PT (0.8)

FortisBC Energy Inc

Business Services

As at December 31, 2011

Advance Metering
Program Leader
(1)

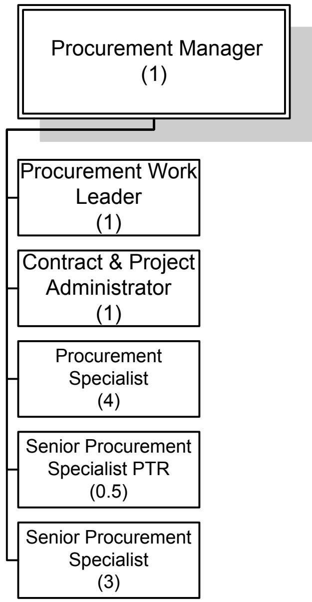
FortisBC Energy Inc

Business Services

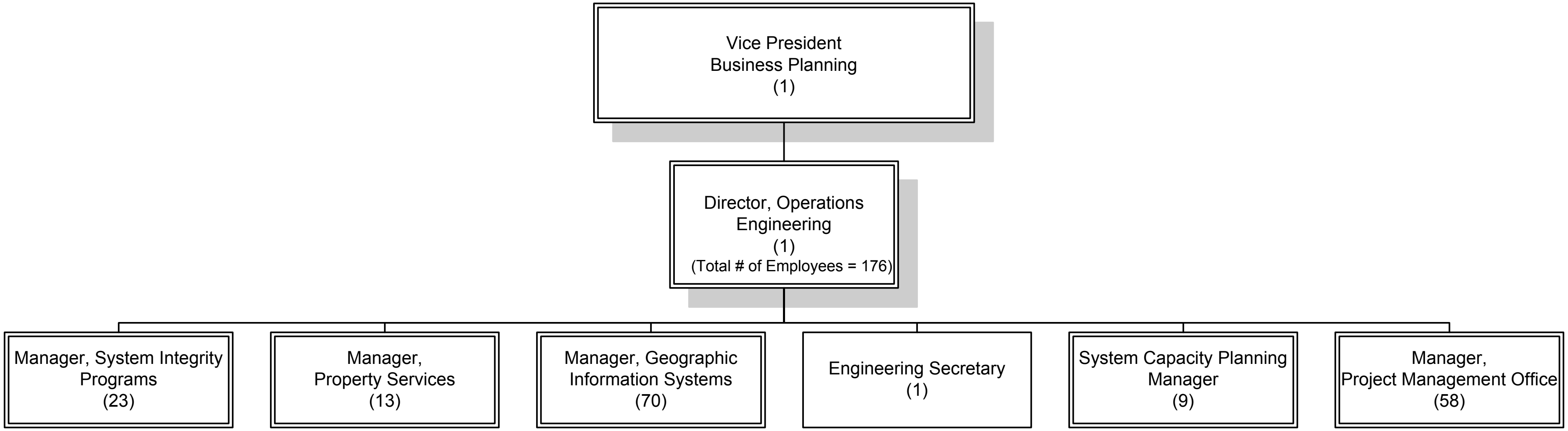
As at December 31, 2011

- Measurement Services Manager (1)
  - Technologist 4 QA Workleader (1)
  - Measurement Services Business Analyst (1)
  - Measurement Tech 3 (3)
  - Measurement Tech 3 (1)
  - Measurement Tech Business Analyst (2)
  - Measurement Tech Assistant PTR (.06)
  - Operations Support Assistant (2)
  - Operations Assistant (1)

FortisBC Energy Inc
Business Services
As at December 31, 2011



FortisBC Energy Inc
Business Services
As at December 31, 2011



FortisBC Energy Inc

Business Services

As at December 31, 2011

- Manager, System Integrity Programs (1)
  - Integrity Engineer (3)
  - Inventory/Corrosion Control Analyst 1 (2)
  - System Integrity Eng – Geotechnical (1)
  - Geotechnical Engineer (1)
  - Corrosion Control Manager (1)
    - Workleader Corrosion Control (2.5)
    - Techn 4 - Corrosion Control (9.5)
    - Techn 2 - Corrosion Control (1)
    - Techn 3 - Corrosion Control (1)

FortisBC Energy Inc
Business Services
As at December 31, 2011

- Manager, Property Services (1)
  - Pipeline Right of Way Representative (2)
  - Transmission Permit Representative (1)
  - Property Services Clerk (1)
  - Land Administrator (2.8)
  - Property Tax Specialist (1)
  - Technologist 4 - Environmental Support (1)
  - Land Representative (1)
  - Right of Way Project Coordinator (1)
  - Property Representative (1)

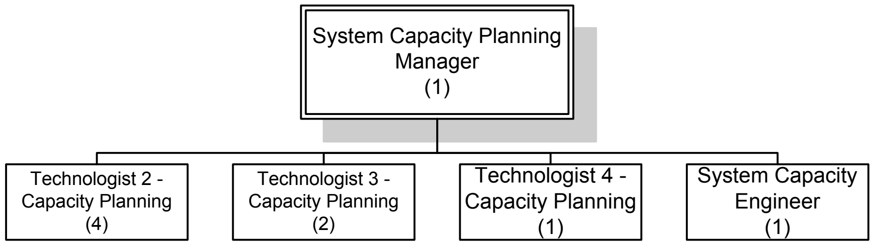
FortisBC Energy Inc
Business Services
As at December 31, 2011

- Manager, Geographic Information Systems (1)
  - Data Integrity Manager (1)
    - Operations Support Rep Work Leader (1)
      - Operations Support Representative 3 (4)
      - Operations Support Representative 2 (21.5)
    - AM/FM Completions Work Leader (1)
      - Operations Support Representative 2 (5)
      - Operations Support Representative 2 (1)
      - Operations Support Representative 3 (3)
  - Engineering Clerk (2)
  - Engineering Drafting Work Leader (1)
    - QA/QC Technician (2)
    - Engineering Drafter 2 (2)
    - Tech 3-Geographic Info Systems (3)
    - Engineer Drafter 3 (1)
  - Production Process Manager (1)
  - Records Professional (1)
  - GIS Drafter Leader (1)
    - GIS Drafter 1 (9)
    - GIS Drafter 2 (3)
    - GIS Drafter 3 (3)
    - Operation Support Rep 2 (1)
    - Operation Support Rep 2 (1)

FortisBC Energy Inc

Business Services

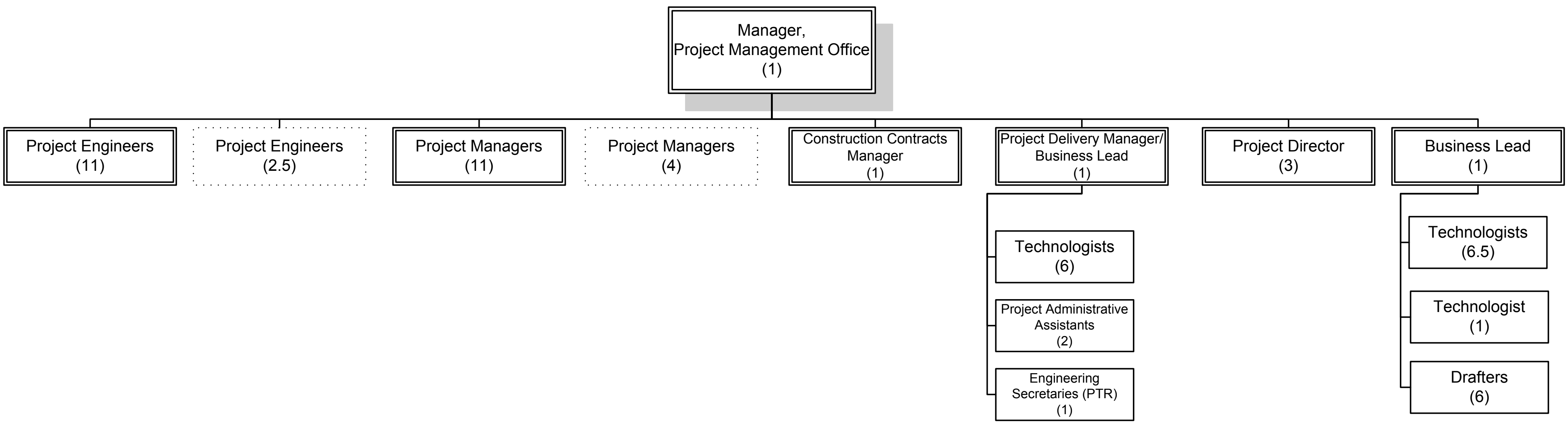
As at December 31, 2011



FortisBC Energy Inc

Business Services

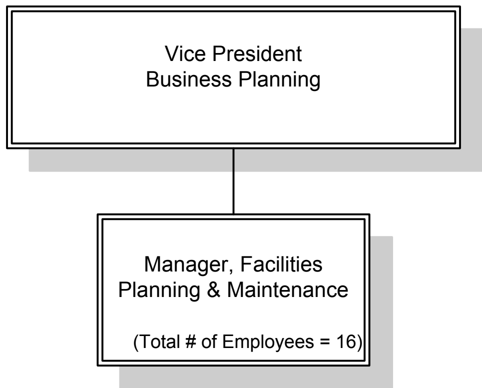
As at December 31, 2011



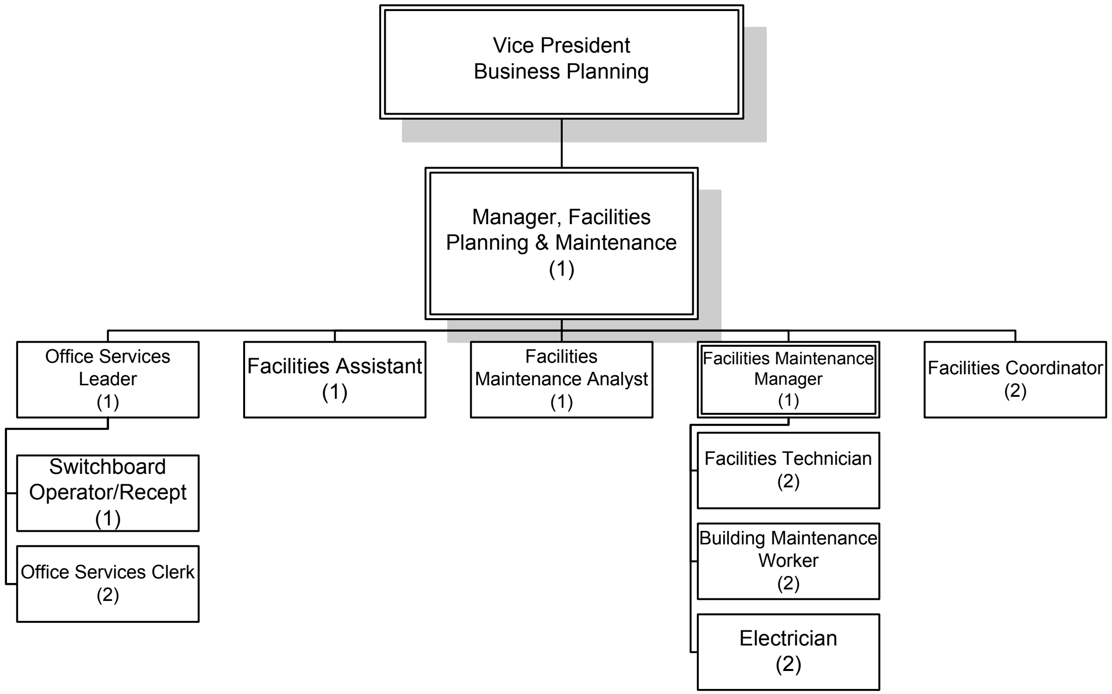
FortisBC Energy Inc

Business Services

As at December 31, 2011



FortisBC Energy Inc
Business Services
As at December 31, 2011



FortisBC Energy Inc
Business Services
As at December 31, 2011

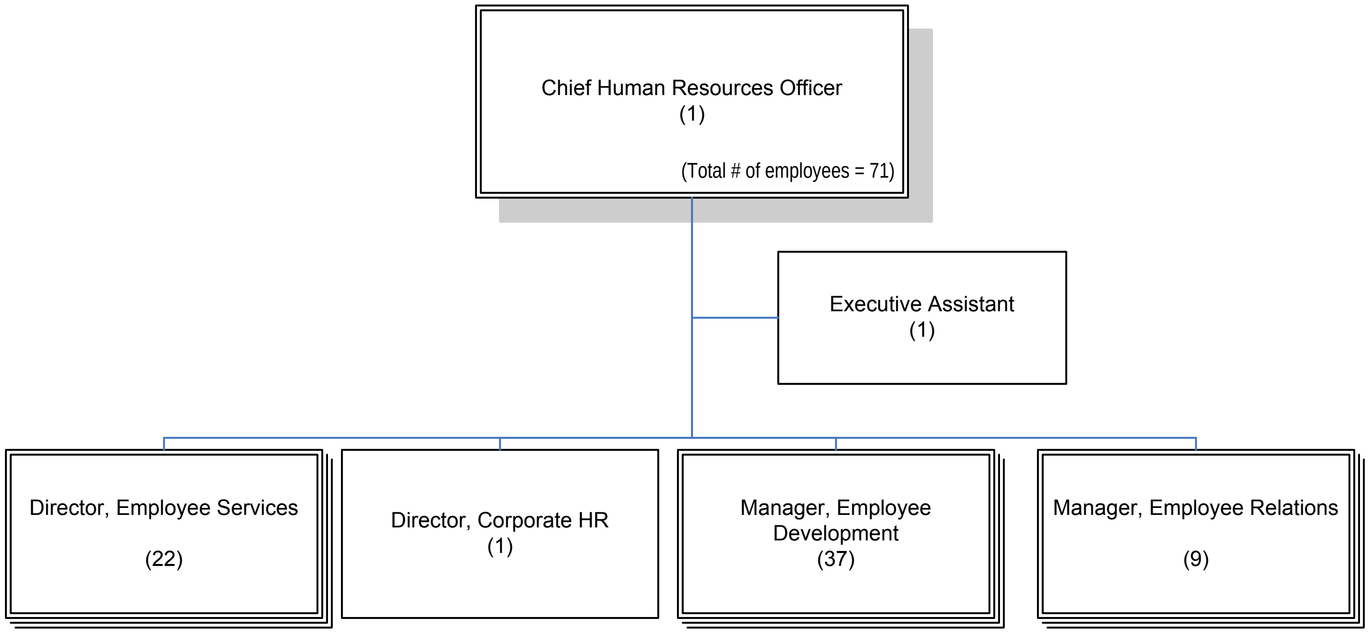
Vice President
Business Planning

- Manager, Facilities Planning & Maintenance *(# of employees = 16)*
  - Office Services Leader (4)
  - Facilities Coordinator (3)
  - Facilities Maintenance Analyst (1)
  - Facilities Maintenance Manager (6)
  - Facilities Assistant (1)

FORTISBC ENERGY INC.

HUMAN RESOURCES

As at December 31, 2011



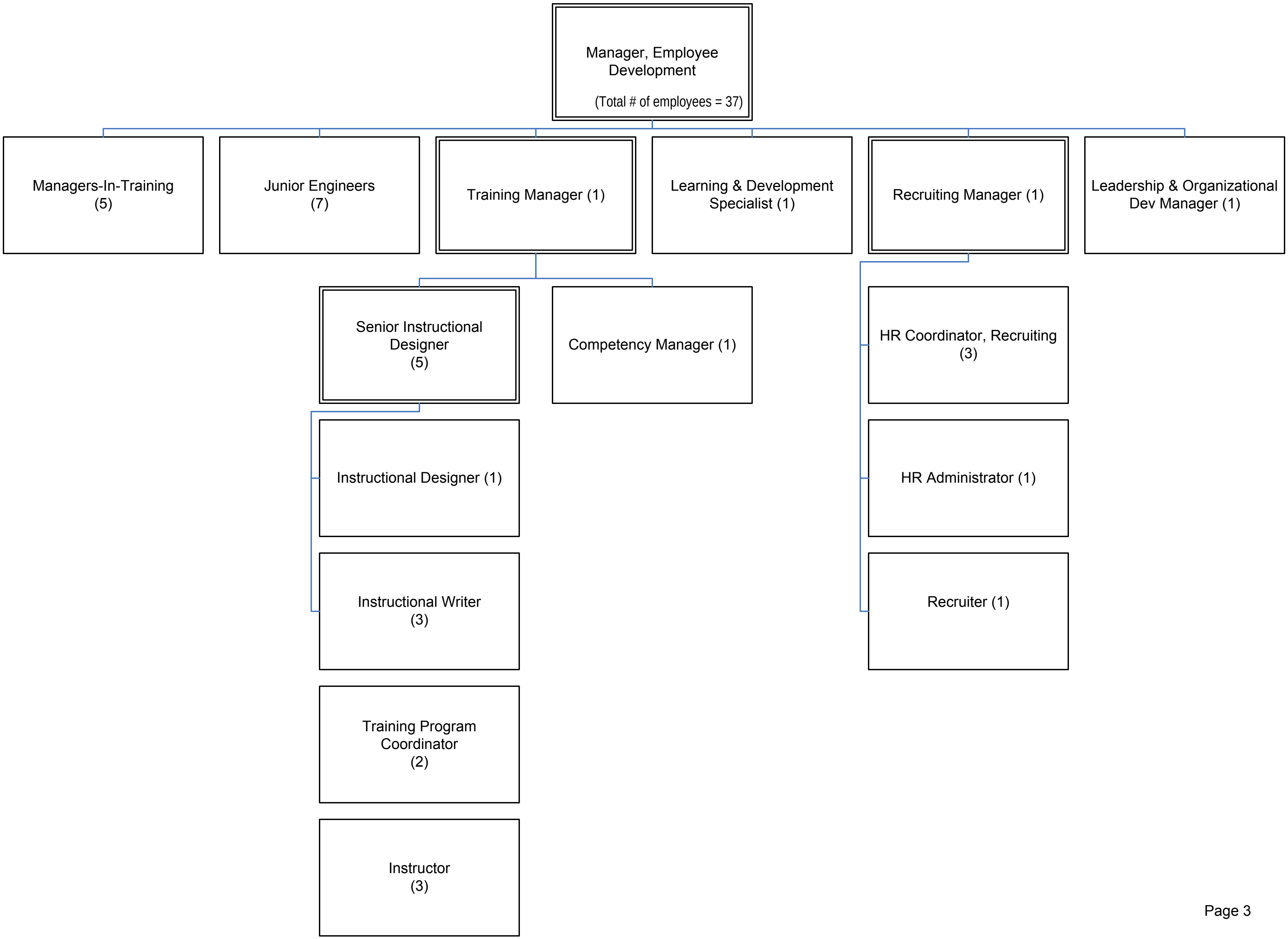
FORTISBC ENERGY INC.

HUMAN RESOURCES

As at December 31, 2011

- Director, Employee Services (1)
  (Total # of employees =22)
  - Total Rewards Communication Coordinator (1)
  - Compensation & Benefits Analyst (1)
  - Manager, HRIS/Payroll (1)
    - HR Associate, HRIS (1)
    - M&E Payroll Coordinator (1)
    - Payroll Administrator (2)
    - Time Administrator (4)
    - HRIS Analyst (1)
    - Business Analyst (1)
  - Manager, Compensation, Benefits & Eserv (1)
  - Corporate Pension Manager (1)
    - Pension Specialist (1)
    - Pension Coordinator (1)
  - Compensation & Classification Advisor (1)
  - Team Leader - Employee Services (1)
    - HR Representative, Employee Services (2)

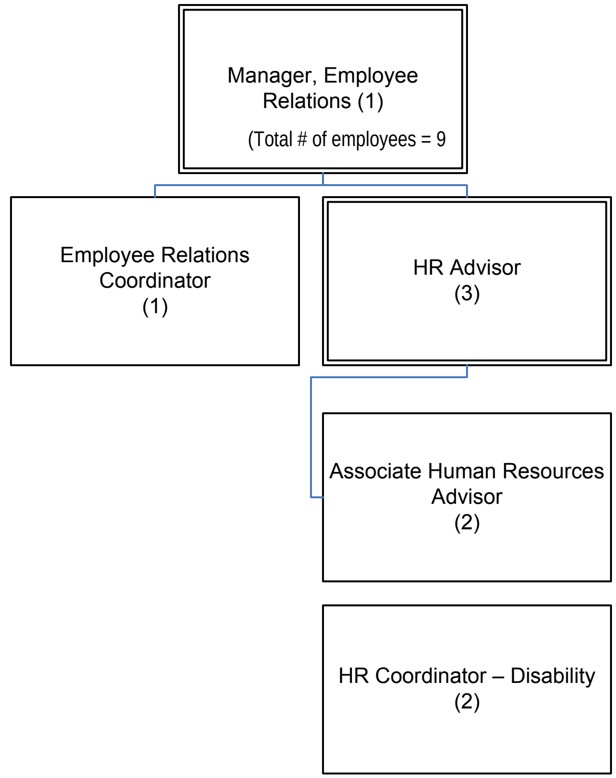
FORTISBC ENERGY INC.
HUMAN RESOURCES
As at December 31, 2011



FORTISBC ENERGY INC.

HUMAN RESOURCES

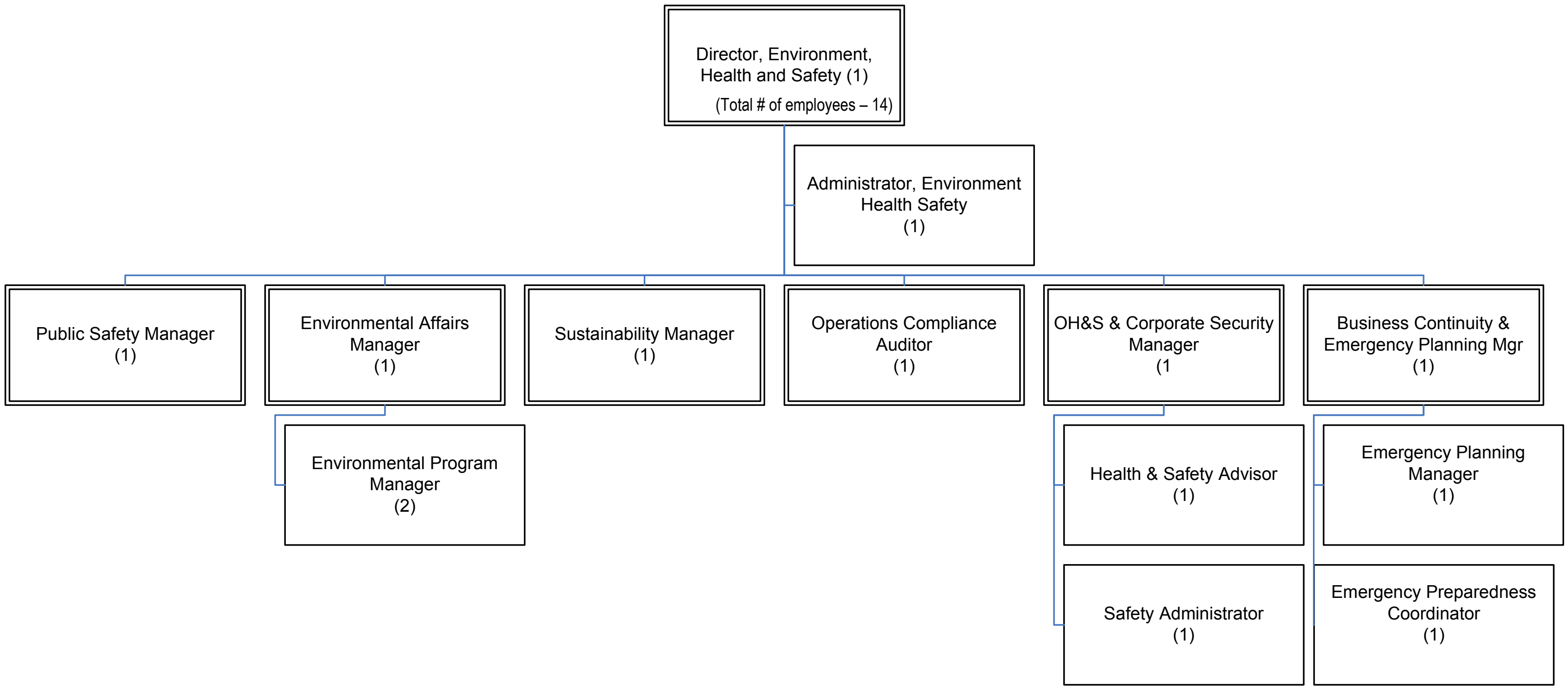
As at December 31, 2011



FORTISBC ENERGY INC.

ENVIRONMENT, HEALTH & SAFETY

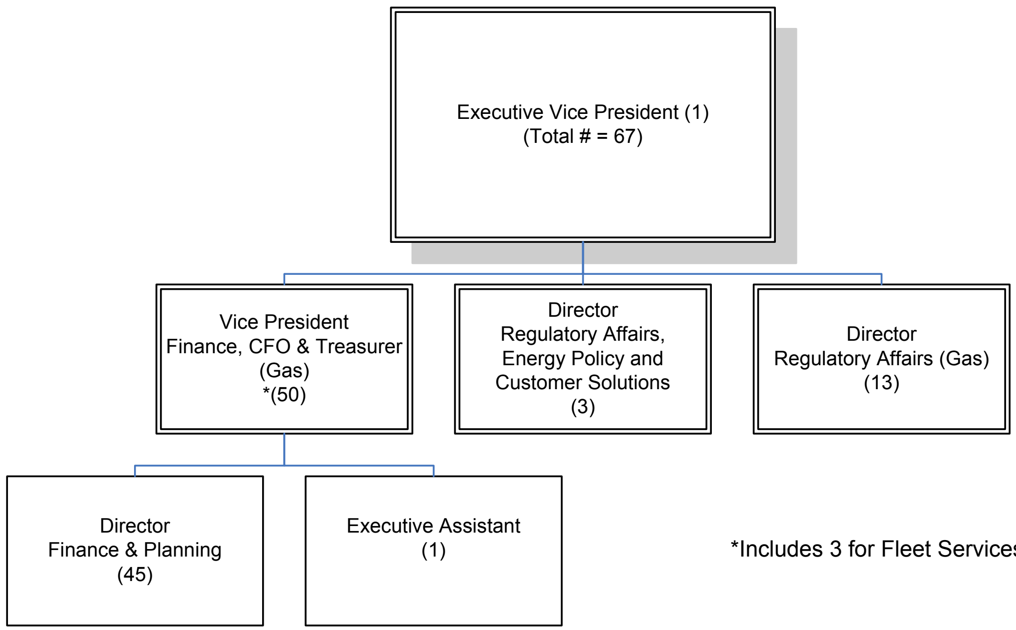
As at December 31, 2011



FORTISBC ENERGY INC.

FINANCE & REGULATORY AFFAIRS

As at December 31, 2011



*Includes 3 for Fleet Services

FORTISBC ENERGY INC.

FINANCE

As at December 31, 2011

- Director Finance & Planning (1) (45) *
  - **Financial Process & Control Manager** (Vacant) (1)
  - **Financial Reporting Manager (3)** (10)
  - **Manager** Financial Planning & Control (15)
  - **Asset Accounting Manager** (4)
  - **Financial Process & Support Manager** (12)

* includes two corporate positions funded by FortisBC Holdings Inc.

FORTISBC ENERGY INC.

FINANCE

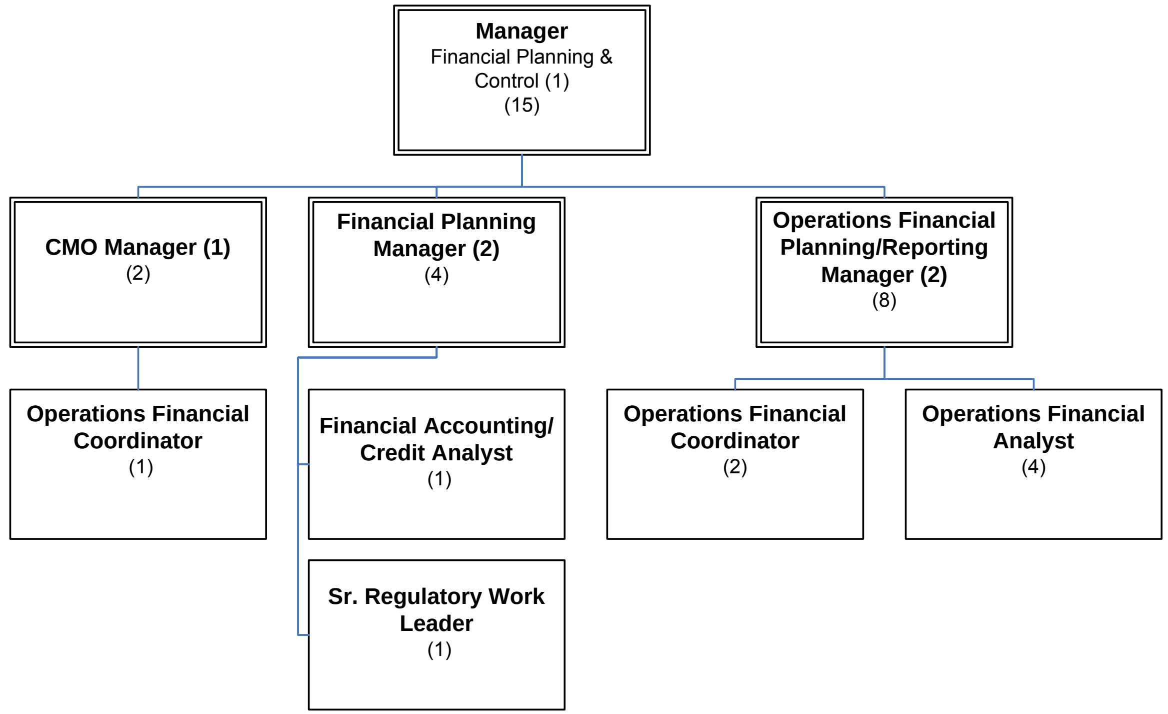
As at December 31, 2011

- **Financial Process & Control Manager** (Vacant) (1)
- **Financial Reporting Managers (3)** (10)
  - **Financial Accounting Clerk 4** (3)
  - **Financial Accounting Analyst** (3)
  - **Financial Accounting Clerk** (3)
- **Manager** Financial Planning & Control (15)
  - **Financial Planning Manager** (4)
  - **Operations Financial Planning Manager** (8)
  - **CMO Manager** (2)
- **Asset Accounting Manager** (4)
  - **Asset Accounting Analyst 2** (3)
- **Financial Process & Support Manager** (12)
  - **Accounts Payable Support Clerk** (1)
  - **Accounts Payable System Support Analyst** (1)
  - **Accounts Payable Leader** (1)
  - **Credit Card Administrator** (2)
  - **Accounts Payable Clerk 2** (5)
  - **Financial Accounting Clerk 3** (1)

FORTISBC ENERGY INC.

FINANCE

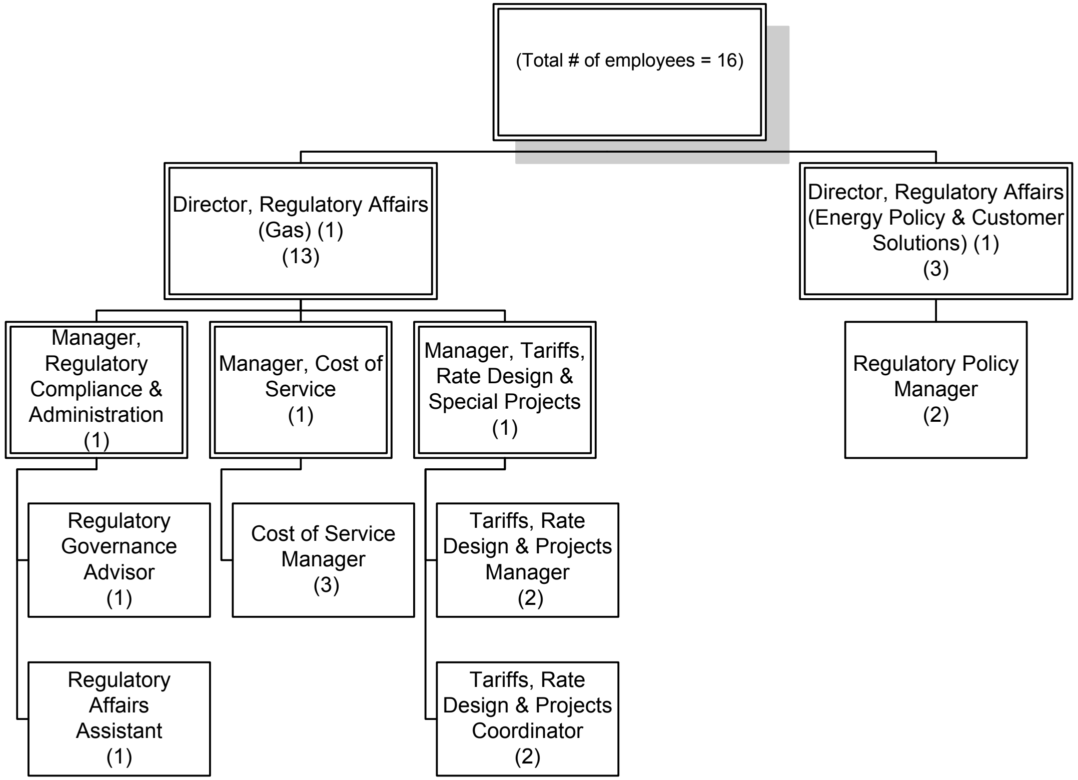
As at December 31, 2011



FORTISBC ENERGY INC.

REGULATORY AFFAIRS

As at December 31, 2011



Appendix I

CNG AND LNG FUELING REPORT

1 OVERVIEW

On December 1, 2010 FortisBC Energy Inc. ("FEI" or the "Company")[1] submitted its Application for Approval of a Service Agreement for Compressed Natural Gas ("CNG") Service and for Approval of General Terms and Conditions ("GT&Cs") for CNG and Liquefied Natural Gas ("LNG") Service (the "NGV Application") to the Commission. On December 6, 2010, the Commission issued Order G-181-10 establishing a Regulatory Timetable for consideration of the NGV Application. On April 13, 2010, FEI submitted to the Commission and Interveners our Final Written Reply Submission, and at the time that this RRA was submitted the NGV Application was still before the Commission for approval. Given customer support[2] for the NGV Application and the benefits the offering will confer upon natural gas customers, we have included in this 2012-2013 Revenue Requirements Application (the "RRA") our project costs and revenue to undertake this business for this period. These costs have been integrated into our rate base and O&M forecasts, however the detail provided in this Appendix allows the reader to identify these costs independently.

The NGV Application proposes a model for FEI to own and operate refuelling stations for natural gas vehicle ("NGV") customers in a manner which ensures that all FEI customers benefit from the increased system throughput resulting from NGV volumes, while ensuring that the forecast incremental costs of FEI owning and operating these stations are recovered through a contract rate charged to these incremental customers. The proposed rate structures require firm "take-or-pay" (i.e. minimum contract demand) commitments, with rates set to recover from the particular customer over the term of the service agreement the cost of investing in and maintaining CNG/LNG facilities located on the customer's property to permit fueling. FEI is targeting commercial, return-to-base fleet of buses, heavy duty trucks, vocational trucks, and marine vessels.

The forecasts made in relation to NGV fueling infrastructure in the Application and in this Appendix are premised on the assumption that the NGV Application will be approved as filed and all approvals sought will be granted. The forecasts are further premised on the assumption that the EEC incentives for NGVs from the Innovative Technology Program Area will continue during the test period of this RRA[3]. The growth of the NGV fueling business is inherently reliant upon the adoption of NGVs in our service territory and the Utilities believe that the adoption of NGVs in our service territory depends upon the continued availability of these EEC incentives

[1] In this RRA, NGV initiatives are described as only occurring within the FEI service territory. The Company's NGV initiatives have not yet attracted participants within FEVI for two main reasons. Firstly, most high mileage fleet operators are based in the Lower Mainland and central regions of BC. Secondly, the higher delivery rate of natural gas within FEVI reduces the price differential between diesel and natural gas, and the overall attractiveness of CNG and LNG as a transportation fuel.

[2] Final Submission Arguments from Registered Interveners BCSEA, BCOAPO, and CEC generally support the proposed NGV Application. Also see Letters of Support in Appendix F of the NGV Application.

[3] These incentives are presently under review through the process initiated by Commission Letter L-30-11.

for NGV adoption. The Utilities wish to make clear that there is no conditional connection between EEC incentives for NGV and the need for the Utilities to also build and operate the NGV fueling stations, other than that the availability of both as options are required in order to see the NGV adoption required to provide meaningful and material benefit to our existing customers.

The O&M resources that were approved in our previous RRA for 2010-2011 are sufficient to manage the forecast growth of the NGV fueling business for the 2012-2013 test period. As a result, there is no incremental O&M requirement for the ES&ER group being proposed at this time specifically for NGV. As agreed to in Item 14 (b) of the NSA, *"the marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates."*[4] The O&M costs in other departments are detailed in Section 5 of this Appendix.[5]

As the NGV fueling business increases in size over time, FEI expects that the need may arise for additional customer education and personnel to manage the growth of the business; however, there are no such incremental expenditures proposed for the test period of 2012 and 2013.

The Utilities presented a preliminary 20 year volume forecast estimate for NGV in the 2010 Long Term Resource Plan ("LTRP"), which was filed on July 15, 2010. The demand scenarios described in that filing were subsequently updated in the NGV Application.[6] Any discrepancies in forecast data between the LTRP and the NGV Application were due to updates in project information, refinement of baseline assumptions, and the availability of new data sources. The NGV Application also included preliminary fueling station forecasts and capital costs which were not discussed in the LTRP. In this RRA, the Utilities have again updated these projections and refined its assumptions based on contractual commitments with customers and actual project costs for the short term (2012 and 2013).

The Utilities have separated the costs and strategies of its NGV initiatives in this Appendix of the RRA, which is structured in the following order:

1. Fueling Infrastructure Investments
    a. Volume Projections
    b. Fueling Station Capital and Annual O&M
2. Revenue from NGV Initiatives
    a. Revenues from Transportation Rate Schedules

4 Commission Order No G-141-09, at page 10.
5 Other departments include Energy Products and Services, Commercial and Industrial Sales, Project Management Office
6 CNG/LNG Application, Appendix A-1, Section 3

   b. Fueling Service Revenues
   c. Rate Schedule 16 Revenues and Associated O&M
3. Main Extensions Costs Associated with Serving NGV Customers
4. General O&M Cost Estimate for 2010 and 2011

2 FUELING INFRASTRUCTURE INVESTMENTS

Offering CNG and LNG Services requires modest investments in fueling infrastructure, the cost of which is to be recovered through contractual rates charged to the fleet customer. Such investments are only made by FEI if service agreements are executed with the customer, filed with and approved by the Commission as proposed in the NGV Application. At this time, FEI has entered into contractual agreements with one customer to provide fueling infrastructure and anticipates two forthcoming agreements which will be filed with the Commission. The infrastructure costs from these three customers have or will be incurred during 2010 and 2011. Negotiations with future customers are ongoing, and have been captured in the volume and cost projections in this RRA.

2.1 Volume Projections

The volume projections in this Appendix includes the fueling service projects where FEI has contractual commitments with NGV customers, future customers with whom FEI has engaged, and future potential customers. A primary barrier to NGV adoption in BC is the high upfront capital cost of NGVs versus their diesel equivalents. In developing this forecast, FEI has assumed that incentive funding to help cover this incremental cost will be available through EEC's Innovative Technologies Program Area.[7] FEI's request in this RRA for EEC funding under the Innovative Technologies Program Area includes approximately $8 million in 2012 and $12 million in 2013 to fund NGV initiatives, for a total of $20 million over two years. In Appendix K of this RRA, this $20 million request is expressed as $10 million in 2012 and $10 million in 2013. FEI recognizes the relative uncertainty of its NGV forecast and as the adoption of NGVs in BC is minimal and relatively unpredictable at this time. In addition, the incremental capital cost of NGVs varies per application. Table I-1 below expresses this $20 million request over two years, and the potential number of NGVs that could be incented.

[7] See Section 10 of the 2010 EEC Annual Report filed March 31, 2011

Table I-1: Estimated Number of NGVs funded by EEC incentives

Category	EEC funding for NGVs		Average Number of Vehicles	
	2012	2013	2012	2013
CNG				
Garbage Trucks	$ 2,050,000	$ 1,390,000	41	28
Transit/School Buses	$ 1,600,000	$ 1,000,000	26	16
LNG				
Class 8 tractors	$ 4,400,000	$ 5,800,000	39	52
Marine Vessels	$ -	$ 3,500,000	0	1
Total:	$ 8,050,000	$ 11,690,000	106	96

Note: Incremental cost assumptions are Class 8 tractors $90,000, Vocational truck $40,000, Bus $50,000, Marine $3.5 million. Funding at 80% of incremental cost, except for marine

The number of vehicles in Table I-1 feed into the volume forecast presented next.
FEI has historically provided natural gas destined for the CNG transportation customers through Rate Schedules 6, 22, 23, 25, 26 and 27. These customers and their energy demands for 2012 and 2013 continue to be part of the forecast demand that is presented in Section 4 of this application.

Since FEI does not provide compression and dispensing service through these rates, customers must seek out fueling service providers to receive a complete end-to-end service offering. FEI's NGV Application, if approved, could provide customers with a complete, end-to-end service offering. Commission Order No. G-65-09 issued on June 4, 2009, approved Rate Schedule 16 Interruptible Liquefied Natural Gas Sales and Dispensing Service ("Rate Schedule 16") as a five-year pilot. Rate Schedule 16 gives the Company the ability to provide LNG supply in tank truck quantities from the Tilbury LNG bulk storage facility.

The NGV volume projections in this Appendix are presented by the Transportation Service Rate Schedules from which FEI expects its customers will receive gas supply. FEI has also divided its volume projections by each fuel type – CNG and LNG. The volumes presented below are used to calculate the revenues associated under each according Rate Schedule, as well as the fueling service revenues.

2.1.1 CNG VOLUMES

FEI received Decision Order G-6-11 on January 14, 2011, granting interim approval of CNG Service for refuse hauler Waste Management to fuel their fleet of 20 garbage trucks. This service agreement includes a 'take-or-pay" volume of 1,583 GJ per month, or approximately 19,000 GJ per year. Based on data from WM, the expected volume is 21,140 GJ per year. The initial term of the fueling service agreement is 10 years, with service commencing in Q1 of 2011. If the agreement with WM is approved on a permanent basis, FEI expects WM will consume gas under Rate Schedules 14A and 25, as well as the proposed CNG Service contract rate. WM anticipates adding more CNG trucks over the next few years to eventually convert their entire fleet of 100 trucks on to CNG.

FEI is endeavouring to enter into a contract to provide CNG Service with one other customer at this time. Okanagan School District No. 23 sought CNG Service to fuel its fleet of 13 school buses and light duty trucks, which could consume an estimated 6,000 GJ per year.[8] The terms and conditions of this agreement have not yet been negotiated, however service could commence in Q2 or Q3 of 2011. City of Surrey also operates one CNG garbage truck which is expected to consume approximately 1,500 GJ per year starting in Q2 of 2011. This customer presently owns and operates private fueling infrastructure on their premises and does not require CNG Service from FEI. In the future, however, City of Surrey anticipates contracting service for an additional 47 garbage trucks in late 2011, representing approximately 58,000 GJ per year.[9] Other potential CNG projects are in varying stages of development.

Over the near term, FEI anticipates incremental CNG demand will increase from 22,500 GJ in 2011 to 131,000 GJ in 2012 and 206,000 GJ in 2013 (see Table I-2 below). This includes the NGV customers described above,[10] plus the incremental load from vehicles additions due to the EEC funding for approximately 67 vehicles in 2012 and 44 vehicles in 2013.

Table I-2: Forecast CNG volume exceeds 200,000 GJ in 2013[11]

	Total Volume (GJ)		
	2011	**2012**	**2013**
Transportation Rate Schedule			
Rate Schedule 6	4,500	4,500	4,500
Rate Schedule 23	1,800	7,006	16,006
Rate Schedule 25	16,200	119,528	185,528
Total:	**22,500**	**131,034**	**206,034**

2.1.2 LNG VOLUMES

FEI is currently negotiating a service agreement with one LNG customer, Vedder Transport ("Vedder"), and is pursuing other potential customers. Vedder has purchased 50 LNG Class 8 tractors which are expected to commence a phased-in operating period in Q3 of 2011. The

[8] Under Rate Schedule 23

[9] Under Rate Schedule 25, with fueling service commencing in 2012.

[10] Volume estimates include WM in 2011 (16,200 GJ), 2012 (42,000 GJ) and 2013 (63,000 GJ); Kelowna School District in 2011 (1,800 GJ), 2012 (6,006 GJ), and 2013 (6,006 GJ); and City of Surrey in 2012 (57,528 GJ) and 2013 (57,528 GJ). Only WM has interim contract approval at this time. Incremental volumes from other potential customers represent the balance during these years. A lag may exist between when vehicles are purchased, delivered and ready for fueling service.

[11] Volumes under Rate Schedule 6 represent pre-existing light duty vehicles fueling at FEI's Surrey Operations and Burnaby facilities, pending submission and approval of an application to the Commission.

anticipated volume represents approximately 138,500 GJ per year, with LNG supplied under Rate Schedule 16. If approved by the Commission and operationally successful, Vedder could add more tractors in the future to their sizeable fleet. Table I-3 below also includes incremental load additions in 2012 and 2013 from another two trucking companies which have engaged FEI in preliminary discussions for LNG Service. The forecast includes the Vedder volumes[12] plus the incremental load from additional vehicles due to the EEC funding for approximately 39 tractors in 2012 and 52 tractors in 2013 (see Table I-1). FEI also estimates LNG Service development into the marine segment with an initial marine vessel funded during 2013.

Table I-3: Forecast LNG volume exceeds 500,000 GJ in 2013

	Total Volume (GJ)		
	2011	**2012**	**2013**
Transportation Rate Schedule			
Rate Schedule 16	57,500	385,500	535,750

Rate Schedule 16 presently has status as a pilot program which expires on December 31, 2014. The impact of this issue, amongst others, was contemplated during the NGV Application proceeding. From FEI's response to BCUC IR 3.20.1:

> *"FEI intends to make an application to the Commission in regards to the future of Rate Schedule 16 at a later date. Given that the pilot program has yet to yield a LNG customer despite significant market and government interest in LNG for transportation applications, FEI believes that approval of our proposed model for offering LNG refueling services in this Application will finally allow the LNG refueling market to develop in British Columbia, and as such, will likely necessitate a possible expansion and/or a permanence to the services offered under Rate Schedule 16."*

A 1,040 GJ per day supply limitation also exists under Rate Schedule 16. If FEI contracts 1,040 GJ for 365 days, a volume of 379,600 GJ per year would be reached. Based on Table I-3 above, FEI's fuel demand estimate would surpass the 379,600 GJ level at the end of 2012, necessitating supply beyond the 1,040 GJ per day limitation. This topic would also be addressed in a future application to the Commission. FEI believes that it would be premature to address this issue at this time given a decision on the NGV Application is forthcoming and no LNG service agreement has been filed with or approved by the Commission.

12 Volume estimates include Vedder in 2011 (57,500 GJ), 2012 (138,500 GJ) and 2013 (138,500 GJ) and Wastech Services in 2012 (193,000 GJ) and 2013 (193,000 GJ). Incremental volumes from other potential customers represent the balance during these years. A lag may exist between when vehicles are purchased, delivered and ready for fueling service. This means load additions do not necessarily occur in the same year as incentive payments are issued.

In summary, the CNG and LNG volume estimates presented in this subsection will continue to be refined and updated as future service agreements are negotiated and executed with the customer, filed with and approved by the Commission.

2.2 Fueling Station Capital and Annual O&M

The "take-or-pay" contract rates negotiated with NGV customers are set to recover the cost of investing in and maintaining CNG and LNG facilities occurring during the term of the service agreement. The forecast cost estimates in this Appendix are to be recovered in this manner.[13]

At this time, FEI has completed the construction of the Waste Management fueling service project. The cost for this station, and the CNG station for Kelowna School District, was considered when developing the capital cost estimates in the forecast presented below. FEI has also entered into negotiations with Vedder Transport to provide LNG Service at its Abbotsford, BC facility. Since CNG and LNG fueling stations vary in their scope, size and load requirements, FEI has made the following cost assumptions which are used in this forecast.

Table I-4: CNG / LNG Station Capital Cost and Annual O&M Assumptions[14]

Rate Schedule	Estimate Avg Station Cost (in thousands)	Estimate Annual O&M (in thousands)
CNG		
Rate Schedule 6	$400	$15
Rate Schedule 23	$400	$15
Rate Schedule 25	$1,000	$25
LNG		
Rate Schedule 16	$2,000	$60

The station capital cost estimates are based upon the projects completed to date and the quotations received during the project procurement process. The station capital cost includes major equipment (CNG compressor/LNG storage), dispensing equipment, field piping, civil and electrical work, engineering and project management costs, as well as commissioning and permitting fees. The annual O&M costs are estimates based on information from our manufacturers for each corresponding fueling facility, as well as FEI's prior experience operating and maintaining CNG fueling stations. CNG and LNG O&M cost estimates include the cost of safety inspections and preventative and routine maintenance as recommended by the

[13] Would not include public fueling service provided through FEI's Surrey and Burnaby fueling stations, pending filing with and approval by the Commission.

[14] FEI has estimated which Rate Schedule each category of NGV customer would take gas service under. In this Appendix, Rate Schedule 6 refers to light duty vehicles, Rate Schedule 23 refers to buses and medium duty trucks, Rate Schedule 25 refers to vocational trucks, and Rate Schedule 16 refers to Class 8 LNG tractors and marine vessels.

manufacturer. The cost of electricity for the facility is paid by the CNG or LNG customer and not included in these O&M cost estimates.

2.2.1 NUMBER OF FUELING STATIONS

Based on the volume assumptions for CNG in Table I-2 and LNG in Table I-3, the Company has developed an estimate of the number of fueling stations required from 2011 through 2013. FEI has also considered the redundancy (in other terms "excess capacity") provided in the near term by the fueling stations for WM and Vedder. The WM facility was designed to fuel approximately 60 trucks without substantive incremental capital investment. Similarly, the LNG station at Vedder is being designed to service additional vehicles as additional dispensing pumps have been incorporated into the design of this facility. However, like other potential LNG facilities, the station's fueling capacity is primarily tied to the frequency of LNG deliveries from Tilbury.

Table I-5: CNG and LNG Fueling Station growth to 11 by 2013

	Estimated Number of Stations		
Transportation Rate Schedule	**2011**	**2012**	**2013**
CNG			
Rate Schedule 6	1	1	2
Rate Schedule 23	1	1	2
Rate Schedule 25	1	3	4
LNG			
Rate Schedule 16	1	2	3
Total:	**4**	**7**	**11**
Annual Incremental:	**4**	**3**	**4**

The capital investments of providing this fueling infrastructure is discussed in the following subsection.

2.2.2 STATION CAPITAL AND ANNUAL O&M FROM 2011 THROUGH 2013

FEI has multiplied the cost assumptions in Table I-4 by the estimated number of fueling stations in Table I-5 to produce a future forecast of the total costs for FEI's NGV initiatives. The capital requirements for station capital and annual O&M are summarized below by Rate Schedule, in the following Tables I-6 and I-7:

Table I-6: NGV Fueling Station Capital Requirements

Transportation Rate Schedule	NGV Fueling Station Capital Requirements (in thousands) 2011	2012	2013
CNG			
Rate Schedule 6	$400	$400	$800
Rate Schedule 23	$400	$400	$800
Rate Schedule 25	$1,000	$3,000	$4,000
LNG			
Rate Schedule 16	$2,000	$4,000	$6,000
Total:	**$ 3,800**	**$ 7,800**	**$ 11,600**
Annual Incremental:	**$ 3,800**	**$ 4,000**	**$ 3,800**

Table I-6 shows the Company's modest station infrastructure investments, which are approximately $4 million per year for 2012 and 2013.

The annual Distribution O&M for FEI's NGV fueling projects in Table I-7 show annual requirements of approximately $225 thousand in 2012 and an incremental $115 thousand in 2013. These costs are for fueling station maintence.

Table I-7: NGV Annual Distribution O&M Requirements for Fueling Stations

Transportation Rate Schedule	NGV Annual O&M Requirements for Fueling Stations (in thousands) 2011	2012	2013
CNG			
Rate Schedule 6	$0	$15	$30
Rate Schedule 23	$0	$15	$30
Rate Schedule 25	$0	$75	$100
LNG			
Rate Schedule 16	$0	$120	$180
Total:	**$ -**	**$ 225**	**$ 340**
Annual Incremental:	**$ -**	**$ 225**	**$ 115**

The annual Transmission O&M for FEI's NGV fueling projects in Table I-8 show annual requirements of approximately $133 thousand in 2012 and an incremental $106 thousand in 2013. These costs are for increased electricity costs at the Tilbury LNG facility.

Table I-8: NGV Annual Transmission O&M Requirements for Fueling Stations

	NGV Annual O&M Requirements for Fueling Stations (in thousands)		
Transportation Rate Schedule	**2011**	**2012**	**2013**
LGN			
Rate Schedule 16	$ -	$ 133	$ 239
Total:	**$ -**	**$ 133**	**$ 239**
Annual Incremental:	**$ -**	**$ 133**	**$ 106**

The volume forecasts presented in this subsection are used to calculate the expected revenue benefits under each Rate Schedule, as described in the following subsection.

3 REVENUE FROM NGV INITIATIVES

3.1 Revenue from Transportation Rate Schedules

The CNG and LNG volumes presented in Section 2.1 of this Appendix are multiplied by the delivery charge under the corresponding 2011 Rate Schedule to produce a revenue forecast. A summary of the delivery margin revenue associated with CNG and LNG service is presented in Table I-8 below.

Table I-8: Delivery Margin Revenue from CNG/LNG Service[15]

	Transportation Delivery Margin Revenue (in thousands)		
Transportation Rate Schedule	**2011**	**2012**	**2013**
CNG			
Rate Schedule 6	$ 16	$ 16	$ 16
Rate Schedule 23	$ 4	$ 16	$ 37
Rate Schedule 25	$ 10	$ 77	$ 120
LNG			
Rate Schedule 16	$ 228	$ 1,527	$ 2,122
Total:	**$ 259**	**$ 1,636**	**$ 2,295**
Annual Incremental:	**$ 259**	**$ 1,378**	**$ 658**

Note: Delivery Charges are Rate Schedule 6, $3.648, Rate Schedule 23, $2.318,

Rate Schedule 25, $0.645, and Rate Schedule 16, $3.96

15 Revenues under Rate Schedule 6 represent pre-existing light duty vehicles fueling at FEI's Surrey Operations and Burnaby facilities, pending submission and approval of an application to the Commission.

Based on Table I-8 above, FEI anticipates annual increases in its delivery margin from its CNG and LNG Service of approximately $1,378 thousand in 2012 and $658 thousand in 2013. The reason for the expected decline from 2012 to 2013 is primarily due to FEI's funding allocation estimate. FEI anticipates a funding expenditure of $3.5 million for an LNG marine application will occur during 2013, with fueling service beginning in 2014 due to the pilot nature of the project. In absence of a $3.5 million marine expenditure, FEI could alternatively fund approximately 30 LNG Class 8 tractors. These vehicles would likely commence fueling service earlier (during 2013) than a marine application would.

The following subsection discusses the revenues associated with the fueling service agreements (ie. contract rates). Please see Section 5.5 of the RRA for an additional summary on the overall revenues from NGVs.

3.2 Fueling Service Revenues

To calculate the expected fueling service revenues under each Rate Schedule, FEI has multiplied the CNG and LNG volumes from Section 2.1.1 of this Appendix by the contract rate estimates in Table I-9 below.

Table I-9: Fueling Service Contract Rate Assumptions

Customer	Rate Schedule	Contract Rate ($/GJ)
Light Duty Vehicles	6	$5.50
Bus	23	$7.00
Garbage truck	25	$5.25
Class 8 tractor	16	$4.00
Marine Vessel	16	$3.00

These contract rates for fueling service are based on preliminary cost of service estimates for FEI's current and potential CNG and LNG customers.[16] The wide range in rates reflects very different situations regarding the type of fueling infrastructure that is needed and the wide range in gas consumption. Table I-9 does not show the actual contract rates for WM, Kelowna School District, or Vedder Transport, which FEI has kept confidential during negotiations.[17] However these rates, multiplied by the minimum monthly "take-or-pay", have been factored into the revenue forecast presented in the Table I-10 below.

[16] LNG Contract Rate does not include LNG transport and delivery charge

[17] Please refer to CNG/LNG Application Proceeding for rationale surrounding confidentiality of contract rates. The Commission's preliminary approval of the Waste Management contract required publication of rate schedules, but did not preclude confidentiality prior to Commission approval of the service agreement.

Table I-10: Fueling Service Contract Revenues[18]

Vehicle Class	Fueling Service Contract Revenue (in thousands) 2011	2012	2013
CNG			
Light Duty Vehicles	$ 25	$ 25	$ 25
Buses	$ 14	$ 54	$ 117
Garbage Trucks	$ 87	$ 618	$ 967
Total:	$ 126	$ 699	$ 1,114
LNG			
Class 8 Tractors	$ 216	$ 1,411	$ 1,995
Total NGV Revenue:	**$ 341**	**$ 2,107**	**$ 3,104**
Annual Incremental:	**$ 341**	**$ 1,766**	**$ 996**

Based on Table I-10 above, FEI anticipates annual increases in its contract revenues from its CNG and LNG Service of approximately $1.7 million in 2012 and $1 million in 2013. As stated in the delivery margin revenue section, the reason for the expected decline in revenue from 2012 to 2013 is primarily due to FEI's funding allocation estimate.

3.2.1 RATE SCHEDULE 16 REVENUES AND ASSOCIATED O&M

During the NGV Application proceeding, the Commission inquired about the breakdown of the delivery charge under Rate Schedule 16, and the appropriate allocation of costs. The costs incurred to provide Rate Schedule 16 service were discussed in FEI's response to BCUC 2.25.2:

> *"Production of LNG at Tilbury will generate incremental O&M cost associated with increased production of LNG at Tilbury and this cost will partially offset the revenue benefit referred to above. As discussed in the May 7, 2009 Rate Schedule 16 application, this incremental cost is estimated at $1.95/GJ or 52% of the rate. The remaining balance represents contributions that are incremental to existing O&M and capital accounts; thus they provide benefits to all rate payers.*
>
> *The full rate breakdown estimate is shown below:*

[18] Does not include revenues from Delivery, Demand and Fixed Monthly Charges

Table 1 - Rate Breakdown

O&M Charge- Liquefaction, Storage & Dispensing	*$1.95*
Capital Recovery	*$0.97*
Transportation from Huntingdon to Tilbury	*$0.73*
Peaking Arrangement Cost	*$0.08*
Total	***$3.73***

The $3.73 total charge has since increased to $3.89/GJ as a result of the annual rate adjustment as approved by the Commission (Order numbers G-141-09 / G-158-09)."

The delivery rate under Rate Schedule 16 has increased to $3.96 as of January 1, 2011. Therefore the incremental revenue benefits in Table I-8 (from Section 3.1 above) will be offset by approximately 52 percent for the LNG volumes under Rate Schedule 16.

With respect to the cost allocation of future LNG storage requirements, in its response to BCUC IR 3.21.2 in the NGV Application, FEI stated:

"The case for incremental investment in LNG storage would be justified by the benefits provided by such investment and these benefits may not be restricted just to Rate Schedule 16 customers. Incremental investment in LNG storage will directly benefit all NGV customers who use LNG under Rate Schedule 16, hence all members of this customer class should participate in bearing some or all of the costs associated with such investment. However, FEI also notes that incremental storage may also increase the capacity available to service peak load requirements, thereby providing a benefit to all customers. In addition as demonstrated in BCUC IR 2.25.2 and BCUC IR 2.26.1, addition of NGV load also provides load building benefits to all customers. Hence FEI does not rule out the possibility of presenting a case where all customers who benefit from the additional storage participate in sharing the costs. FEI has not made an application for additional investment in storage as part of this application and FEI believes that the best place to address the justification for incremental investment and how the costs will be recovered will be through a CPCN specifically addressing the project if appropriate."

FEI believes that it is not appropriate to address any issues related to Rate Schedule 16 in this RRA given a decision on the NGV Application is forthcoming and no LNG service agreement has been filed with or approved by the Commission.

4 MAIN EXTENSION COSTS ASSOCIATED WITH SERVING NGV CUSTOMERS

The Main Extension ("MX") Test[19] is employed to provide existing customers with some comfort that a main extension will be cost effective from the perspective of the utility. Incremental CNG customers requiring main extensions to bring service to a fueling facility will be subject to the existing MX Test to ensure NGV load is cost-effective (the costs of the fueling facility itself are the subject of the CNG service agreement, not the MX Test). LNG customers are not subject to the MX Test as fuel is being transported to their facility by tanker[20] and not through distribution piping.

When a fleet operator evaluates its fueling options, fuel consumption must be at a volume that makes the conversion to natural gas economical. In FEI's experience, volumes from heavy duty trucking fleets will pass the existing MX test without a CIAC from the customer.[21]

In sum, all potential CNG customers are required to undergo the existing MX Test. At this time, FEI does not anticipate other NGV projects necessitating CIACs to make the extension cost-effective.

5 GENERAL O&M COST ESTIMATE FOR 2010 AND 2011

At this time, there is no forecast incremental O&M requirement for the ES&ER group being proposed specifically for NGV in this RRA for 2012 and 2013. In the NSA, for 2010-2011 for FEI the parties agreed that marketing costs associated with NGV for 2010 and 2011 will be recovered through general O&M. FEI has adopted the same approach in this RRA, as the promotion of NGV represents a part of FEI's core natural gas business. The information set out below breaks out the O&M costs within the ES&ER department for information purposes only.

The O&M costs presented below are estimated costs, rather than actual amounts for the NGV costs within the ES&ER department. FEI was not required to track and report actual amounts for NGV separately during this period 2010-2011 period. These cost estimates do not include time for regulatory activities such as cost of service modelling, NGV Application support and review. FEI estimates a minimal customer education cost will be incurred in 2011 for NGV.

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[19] The MX test protects existing ratepayers by requiring Contribution In Aid of Construction ("CIAC") from the individual customer in the event that the Profitability Index ("PI") s less than 0.8.

[20] NGV customers will be charged for the cost of owning and maintaining FEI's LNG tankers and the associated driver and transport costs.

[21] The WM facility, completed in February of 2011, passed the MX test and did not require a CIAC from the customer. This was due to the high level of expected natural gas volume WM's fleet of vehicles would consume.

Table I-11: O&M Cost Estimate for 2010 and 2011

Department or Activity	2010		2011	
	FTE	Cost Estimate	FTE	Cost Estimate
Business Development Managers	1.3	$ 148,836	1.3	$ 156,241
Energy Products and Service Manager, Commercial & Industrial Sales, Project Manager	2.7	$ 331,439	2.7	$ 345,396
Customer Education	N/A	$ -	N/A	$ 50,000
Total:	**4.0**	**$ 480,275**	**4.0**	**$ 551,637**

Of the 4.0 FTE estimate in the Table I-11, approximately 1.5 are involved in the fueling station installation. The balance of the FTE is involved due to the overall level of NGV activity during this development period. All O&M amounts related to NGV have been appropriately included in the overall O&M forecast for all of our core gas business. The estimates provided in Table I-11 are included here only for informational purposes with the intention of providing an order-of-magnitude of the impact of NGV activities on our O&M.

Appendix J

BIOMETHANE REPORT

1 REGULATORY BACKGROUND

On June 8, 2010, FortisBC Energy Inc. ("FEI")[1] filed an application for the approval of a Biomethane Service Offering and Supporting Business Model, including the approval of the Columbia Shushwap Regional District and Catalyst Power Biomethane Project (the "Biomethane Application"). On December 14, 2010, the British Columbia Utilities Commission (the "BCUC" or "Commission") issued its Decision and Order No. G-194-10 (the "Biomethane Decision"), allowing FEI to move forward with a Biomethane Service Offering/Program for a two year period from the date of the Biomethane Decision and approving the two agreements with Columbia Shushwap Regional District ("CSRD") and Catalyst Power Inc ("Catalyst").

As part of the Biomethane Decision, the Commission further approved the creation of a non-rate base deferral account, Biomethane Variance Account ("BVA"), to capture costs to procure and process consumable biomethane gas as well as revenues collected through biomethane energy recovery components of rates. FEI was directed to provide actual and forecasted biomethane operating and maintenance ("O&M") and capital costs and an analysis of these costs in its next Revenue Requirement Application:

> *"Commencing January 1, 2012, the treatment of all costs related to and resulting from ongoing Biomethane operations will be reviewed by the Commission as a component of Terasen's Revenue Requirements Application (RRA).* ***Within TGI's RRA for 2012 and onwards, Terasen is directed to include a separate section providing actual and forecasted Biomethane operating, maintenance and capital costs and an analysis of these costs.*** *This disclosure is to include, amongst other things, a breakdown of costs incurred by category of past and projected years and an explanation of the financial results experienced and expected in the test period. Details of all accumulations within the BVA should also be provided."*

In addition to the BVA, the Commission also approved two additional new non-rate base deferral accounts ("New Deferral Accounts") to capture costs, as described in the Application, incurred prior to January 1, 2012:

> i) Costs of service associated with the capital additions to the delivery system; and
> ii) Operating and maintenance costs applicable to all customers (attracting AFUDC).

In the Biomethane Decision, the Commission also directed FEI to report on the New Deferral Accounts:

> ***"As part of its 2012 Revenue Requirements Application, TGI is directed to report the total values accumulated in the New Deferral Accounts from inception as well***

[1] Then Terasen Gas Inc. or TGI

as a breakdown of the costs accumulated in the accounts by nature and dollar amount."

As the Biomethane Service Offering is still in its early stages of development, this Report provides a high level overview of FEI's work towards preparation to roll out the Biomethane Service Offering to customers since release of the Biomethane Decision in December 2010. Also, this Report outlines FEI's actual[2] and forecasted capital and O&M costs and provides an analysis of costs in the BVA and New Deferral Accounts, as directed by the Commission in its Biomethane Decision. The forecasted O&M and capital expenditures for the 2012-2013 test periods discussed in this Appendix are included in FEI's overall natural gas Revenue Requirement. FEI has prudently managed its biomethane O&M and capital costs and will continue to do so as the service offering evolves.

2 TAKING STEPS TOWARDS BIOMETHANE SERVICE OFFERING ROLL OUT

The following describes the activities that FEI has undertaken to roll out the Biomethane Service Offering for Phase 1 of the program, which is targeted at FEI Rate Schedule 1, residential customers in the Lower Mainland, Inland and Columbia regions for a 10% blend of biomethane, as approved as Rate 1B[3]. FEI has been making progress to ensure that Phase 1 of Biomethane Service Offering is successful in its roll out to customers.

2.1 Biomethane Service Offering Launch

As stated in the Biomethane Application, FEI had initially anticipated Phase 1 of the Biomethane Service Offering to begin in the Fall of 2010, based on the regulatory timetable initially proposed in the Biomethane Application. However, due to the duration of regulatory process, the timing of the Biomethane Decision in December 2010 and the time required by Customer Works LP to implement the billing changes, Phase 1 of the program launch has been delayed until mid June 2011.

The delay of the Phase 1 offering may push out the Phase 2 offering, which is targeted at small and large commercial customers, Rate Schedules 2 and 3, for a 10% blend of biomethane as well. . The Phase 2 offering was initially anticipated to take place in early 2012. FEI will continue to monitor the customer uptake from the Phase 1 launch, manage supply and eventually expand the product offering to other customer classes and offer higher percent blends when appropriate.

Over the past year FEI has been working with the provincial government to resolve the issue on whether or not the biomethane is carbon tax exempt. FEI is pleased with the progress to date.

2 As at March 31, 2011
3 Order No. G-28-11, effective Date March 1, 2011

The Budget Measures Implementation Act, 2011 (“Bill 2”) is currently before the legislature. Section 3 of Bill 2 amends the Carbon Tax Act to certify biomethane as a carbon-neutral fuel and to insert the language allowing the implementation of the biomethane credit promised in the 2011 provincial Budget. FEI has discussed the implementation of the credit with the Ministry of Finance and received direction that we may proceed with our plan to provide the credit to customers on their bills prior to Bill 2’s passage in the legislature and subsequent royal assent.

2.2 Customer Education

FEI is currently planning for a formal launch of the biomethane program for Residential customers by June 2011. FEI held a focus group session in Vancouver on March 7th 2011 comprised of more than twenty diverse participants to take feedback on several proposed communication concepts. FEI is currently processing feedback received through this focus group session to develop the right communication messaging and channels to achieve maximum customer education. The uptake and interest in Phase 1 will be key to encouraging continued development of additional supply sources allowing expansion of the program to other customer groups.

FEI currently has more than one hundred customers signed up to be notified for when the Biomethane Service Offering begins in early June 2011. FEI expects customer education to be an ongoing activity until the program reaches the level of maturity required for customer groups to make informed decisions whether or not they wish to participate in the program.

2.3 Supply Projects

Development of the two existing supply projects, Columbia Shuswap Regional District and Catalyst, that were approved as part of the Biomethane Decision, is underway to deliver an annual amount in the range of 60,000-70,000 GJs of biomethane into FEI’s distribution system by end of 2011.

2.3.1 CATALYST

The Catalyst project consists of an upgraded biomethane purchase (along with construction and operation of interconnection facilities), and began injecting biomethane into the system in September of 2010. As of March 31, 2011, the project has already delivered over 15,000 GJs into our system. The daily average production has increased steadily since start-up, building towards the minimum contracted volumes. The ramping up of supply volumes has been slower than originally forecasted, but Catalyst is taking steps to increase production levels and is expected to reach minimum contract levels within the contractual start-up window, as significant increases in production levels have been observed in the last few months. Based on the most recent production trends, FEI anticipates Catalyst will inject a minimum cumulative total of

59,000 GJs by the end of 2011 and reach their minimum average daily contract volumes by the end of 2012.

2.3.2 CSRD

The CSRD project includes interconnection facilities as well as an upgrading plant located at a landfill. To date, the interconnection facilities have been designed and fabricated and the main extension has been completed. The upgrading plant is in the final design stage. The CSRD completed the installation of the gas collection and flare system at the landfill and it has been in operation since January 2011.

During the summer and fall of 2010 FEI was cautious about spending on this project while waiting for a final regulatory decision. FEI took advantage of the time to complete more thorough gas sampling of the raw landfill gas to feed into the upgrade plant design. The results showed a difference between actual raw gas composition and expected gas composition. The raw gas contained more nitrogen than expected which had the potential to impact the final heating value of the biomethane negatively. As a result, FEI directed the supplier of the upgrader, Xebec Inc. ("Xebec"), to re-evaluate the design of the upgrading plant to reduce the risk of building a plant that may not be able to process raw biogas to meet the final biomethane specification. Xebec recommended a design change to a different version of their Pressure Swing Adsorption technology that could reliably manage higher levels of nitrogen while still meeting final biomethane specifications. The design change will increase the cost of the upgrading plant by approximately $300,000 from the original approved amount of 1,621,800 and result in a delivery delay. The project is now expected to be commissioned in late 2011 with an injection start date close to year end. Therefore, there will be no significant contribution to the biomethane supply before the end of 2011.

2.3.3 FUTURE PROJECTS

The future projects that FEI is evaluating are still in the contract negotiation stages with earliest possible injection dates in 2012. Currently, the two most likely prospects are the City of Kelowna and Annacis Island projects. The Kelowna landfill project would be structured very similar to the CSRD project with the expected volumes starting approximately at 50,000 GJ/year. The Annacis Island project would be an organic waste digester that would look similar to the Catalyst Project. In this case, however, the project developer is interested in FEI investing in the upgrading plant. The volumes are expected to start at 100,000 GJ/year.

FEI is incorporating lessons learned from the first two supply projects into the new project development. These lessons have informed how FEI estimates costs and allows for contingencies. FEI will ensure that any new supply contracts brought forward for approval meet the established criteria as approved by the BCUC in the Biomethane Decision.

3 BIOMETHANE CAPITAL AND O&M COSTS

This section describes an overview of total capital and O&M costs, including those allocated to customers who purchase biomethane and those allocated to all customers. The tables below provide an overview of forecast costs as described in the Application and approved in the Biomethane Decision, actual costs to date (from beginning of 2010 to end of March 2011), and projected costs for the period of 2012 and 2013. FEI has managed O&M and capital costs within the overall approved budget and will continue to manage costs prudently.

3.1 Capital Costs

FEI's overall capital costs incurred to date from the two approved supply projects are well under the overall approved budget. Additional capital investment will be required as the CSRD site gets commissioned in the coming months.

The Catalyst project is now complete, and the final capital costs are known. The overall costs for the Catalyst project came in well under the approved amount, although the allocation of costs across certain cost categories differs from the original estimate as seen from the table below. FEI's initial assumptions of how costs would arise across certain categories were made during the preliminary design phase. As the project progressed and FEI developed a better understanding of the actual costs and the allocations, FEI re-allocated the costs to match more closely with standard practice used for more established projects like regulator station design and construction. Going forward, FEI will incorporate these learnings into the CSRD project to allocate the expected costs into the appropriate categories as illustrated in the table below under future projects. FEI now has additional categories that are more aligned with the current standard practice in place for established projects such as station design and construction of interconnect facilities. Going forward FEI will report across these asset classes for future biogas supply projects.

For the Upgrading plant under CSRD, FEI anticipates spending an additional $300,000 from the original approved amount to accommodate for the design change as recommended by Xebec to manage higher levels of nitrogen while still meeting final biomethane specifications. Additional details are mentioned under the CSRD section. The BVA will capture such variances and will reflect any adjustments to BERC rate based on deferral account balances at that point in time and these increased costs for the Upgrader will be recovered from biomethane customers who elect into the program.

Capital costs are summarized in Table J-1 which follows.

Table J-1: Biomethane Capital Costs Summary

FEI Biomethane Capital Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013
Capital Costs - All Customers					
Catalyst					
Interconnection(Valves, meter, regulator)	77,300	337,308	337,308		
Quality Monitoring	282,500	99,067	163,999		
Main and main connection costs	227,900	86,393	86,393		
Total Catalyst	587,700	522,768	587,700		
CSRD					
Interconnection(Valves, meter, regulator)	395,500	222,000	395,500		
Quality Monitoring	242,000		253,400		
Main and main connection costs	45,100	33,700	33,700		
Total CSRD	682,600	255,700	682,600		
Future projects					
Structure and Improvements				140,329	140,329
Mains -Muncipal Land				108,993	108,993
Mains-Private Land				61,309	61,309
Regulator & Meter Installations				16,349	16,349
Meters				24,523	24,523
Measuring and Regulating Equipment				663,497	663,497
Total Future Projects				1,015,000	1,015,000
Total Capital Costs - All Customers	**1,270,300**	**778,468**	**1,270,300**	**1,015,000**	**1,015,000**
Capital Costs - Biomethane Customers					
CSRD					
Upgrading Plant	1,621,800	769,200	1,934,000		
Future Projects					
Purification Upgrader				2,062,500	2,562,500
Total Capital Costs - Biomethane Customers	**1,621,800**	**769,200**	**1,934,000**	**2,062,500**	**2,562,500**
Total Capital Costs (All Customers and Biomethane Customers)	**2,892,100**	**1,547,668**	**3,204,300**	**3,077,500**	**3,577,500**
CIAC (ICE AND BCBN funding)	(515,600)	(203,850)	(515,600)		
Total Capital Costs - net of CIAC	**2,376,500**	**1,343,818**	**2,688,700**	**3,077,500**	**3,577,500**

The details of the future projects under consideration are explained under Supply Projects in Section 2.3 above.

3.2 O&M Costs

The O&M costs incurred to date are well within the approved budgeted values for 2011 as stated in the original Biomethane Application. As the Biomethane Program is still in development stages, FEI expects to incur additional costs as the program gets rolled out in June 2011 but expects to stay within the budgeted approved values. FEI has provided the total O&M costs broken out by biomethane Customers and all customers for years 2012 and 2013. The costs for 2012 and 2013 are adjusted by an inflation factor of 2% from the original approved spending amount in 2011.

In the financial schedules accompanying the original Biomethane Application, some O&M costs associated with interconnection facilities were erroneously included in the forecast Biomethane Energy Recovery Charge ("BERC"). As a result, the BERC was calculated to be slightly higher[4] than it should have been based on the Commission-approved approach and the levelized impact on all customers was calculated to be immaterially lower than it should have been. FEI is proposing to defer addressing this miscalculation until the BERC is next changed through the approved process, whereby costs and recoveries will be reviewed on an annual basis as part of FEI's 4th quarter gas cost report to the Commission and any changes to the BERC will be based on deferral account balances at that point in time.

Subject to any unanticipated system and operational risks, FEI does not expect any material changes to the projected capital and O&M costs until the end of 2011 as approved in the Application[5].

O&M costs are summarized in Table J-2 which follows.

[4] Had this been included in the initial Biomethane Application there would have been a downward revision to the price of Biomethane from $9.904/GJ to $9.626/GJ.

[5] Approved O&M of $783,200

Table J-2: Biomethane O&M Costs Summary

FEI Biomethane O&M Costs	Approved Until December 31, 2011	Actual Until March 31, 2011	Projected Until December 31, 2011	Forecast 2012	Forecast 2013****
O&M Costs - All Customers					
Labour Costs	125,000	24,491	125,000	102,000	104,040
Computer Costs				10,000	
Customer Education	400,000	4,600	400,000	300,000	306,000
Internal Reporting Charges	3,200		3,200		
Inbound Calls	35,900		35,900	6,384	6,512
Rate Changes	4,000		4,000		
Application Support	165,600		165,600		
Interconnect Facilities*					
Materials & Supplies	49,500	1,163	49,500	22,500	90,000
Total O&M Costs - All Customers	**783,200**	**30,254**	**783,200**	**440,884**	**506,552**
O&M Costs - Biomethane Customers					
Upgrader Equipment**					
Materials & Supplies	70,000		70,000	123,000	237,000
Customer Related					
Energy Peace Application Support	23,280		23,280		
Enrollment Confirmations (mailings)	3,000		3,000	4,824	4,920
Customer Drops/Finalizations	10,455		10,455	32,080	32,722
Credits to Customers for Heat Content Adjustments	54,000	7,804	54,000		
Reporting & Adminnistration	4,963		4,963		
Process for Updating Premise Heat Zone in New CIS system***				20,000	
Total O&M Costs - Biomethane Customers	**165,698**	**7,804**	**165,698**	**179,904**	**274,642**

* O&M costs for interconnect facilities includes for Catalyst and CSRD and future projects under consideration

** O&M costs for upgrader includes for CSRD and future projects under consideration

*** One time adjustment cost

**** 2013 forecast has been adjusted by an inflation factor of 2% from the 2012 estimates

4 OVERVIEW OF DEFERRAL ACCOUNTS

Table J-3 below provides the actual to date of the program O&M new deferral accounts. The tables following provide the 2010 Actual costs, 2011 Projected costs and the 2012 and 2013 forecast costs for: the BVA (Table J-4); and, the 2010 / 2011 O&M Biomethane Program deferral account and the Biomethane Program – Other Revenue deferral account (Table J-5). As per Biomethane Application and Decision, the Depreciation, Earned Return and related Income Tax are charged to the Biomethane Program Deferral Account.

Table J-3: Biomethane Actual Program New Deferral Accounts

Categories	Notes	Actuals to Date			
		2010	2011		
		Jan-Dec	Jan	Feb	Mar
Catalyst	Captures costs incurred to purchase pipeline ready biomethane	$ 59,570	$ 28,135	$ 21,949	$ 41,562
CSRD	Captures costs incurred to purchase raw biogas, O&M related to upgrader	-	-	-	-
Direct Biomethane Administration	Capture costs for biomethane customer enrollments/account finlization/billing adjustments	-	-	-	-
Biomethane Recoveries	Capture recoveries from biomethane sales at the BERC rate	-	-	-	-

Table J-4: Biomethane Variance Account

	Biomethane Variance Account		2010	2011	2012	2013
				($000's)		
	Volumes (GJ)			61,000	185,750	284,500
*	Cost of Biomethane Purchases		$ 59.6	$ 604.8	$ 1,253.6	$ 1,424.5
*	BVA O&M Activity		-	166.9	179.9	274.6
*	Property Taxes		-	1.0	1.6	1.4
	Depreciation - Upgrader / CIAC		-	(8.6)	202.2	387.2
	Income Tax		-	(126.4)	(246.1)	(372.9)
	Earned Return		-	(0.2)	184.2	343.8
	Other Revenue		-	(126.6)	(61.9)	(29.1)
*	BERC Rate Recoveries @	$ 9.904	-	(604.1)	(1,839.7)	(2,817.7)
	Tax Rate		28.5%	26.5%	25.0%	25.0%
	Tax Offset		(17.0)	(44.7)	101.1	279.3
	Net Additions		42.6	(11.3)	(163.1)	(479.8)
	Balance		$ 42.6	$ 31.3	$ (131.8)	$ (611.6)

Line items marked with an "*" are subject to net-of-tax offset. The negative Earned Return and Income Tax is due to the slightly negative Rate Base which is comprised CIAC that the Company has already received and with the biomethane not going into service until December 2011 the cost of the Upgrader Plant has a relatively smaller Rate Base impact. The negative Income Tax is the result of the timing differences between accelerated deduction provided in the Capital Cost Allowance and booked depreciation (which will begin in 2012). Recoveries are based on the forecast volumes times the current BERC rate which will potentially be adjusted later this year when the fourth quarter gas cost review is filed with the Commission.

Table J-5: 2010 / 2011 Biomethane Program Accounts (O&M and Other Revenue)

	($000's)				
	2010	2011	2012	2013	2014
2010 / 2011 Biomethane Program Accounts					
O&M Deferral Account					
Program O&M Activity	$ 1.2	$ 783.2			
Tax Offset	(0.3)	(207.5)			
AFUDC	0.1	39.4			
Net Additions	1.0	615.1			
Amortization	-	-	(205.3)	(205.3)	(205.3)
Balance	$ 1.0	$ 616.0	$ 410.7	$ 205.3	$ -
Biomethane Program Costs - Other Revenue					
Depreciation	$ -	$ 45.3			
Income Tax	-	8.8			
Earned Return	-	36.0			
Other Revenue	-	44.8			
Amortization	-	-	(30.0)	(30.0)	(30.0)
Balance	$ -	$ 90.1	$ 60.1	$ 30.0	$ -

The costs in the Biomethane – Other Revenue relate to the direct interconnecting facility costs and do not include an allocation of the Overheads Capitalized that would otherwise normally be allocated to the Distribution Mains and Measuring and Regulating Equipment. The amount of Overheads that will be allocated to the Interconnect facilities is dependent on all of the relative direct plant additions costs to which overheads are allocated.

Appendix K-1

EEC

1 INTRODUCTION

On April 16, 2009, the Commission released its Decision and Order No. G-36-09, which approved Energy Efficiency and Conservation ("EEC") funding for the 2009-2010 time period. The approved funding was $41.5 million in aggregate ($34.4 million for FEI and $7.1 million for FEVI for the period 2009 - 2010). FEI and FEVI applied in their respective 2010-2011 RRAs for additional funding for 2010 for interruptible industrial customers and for innovative technologies, and for funding for the overall EEC portfolio for 2011. The Commission approved FEI's and FEVI's NSAs (Order No. G-141-09 for FEI and Order No. G-140-09 for FEVI, both dated November 26, 2009), including the approval of EEC funding for 2010 and 2011.

As contemplated in the FEI and FEVI 2008 EEC application and addressed in Commission Order No. G-36-09, the Companies have established an EEC Stakeholder Group to seek input on the refinement of existing and development of new EEC programs and provide information to stakeholders about progress and development of its overall EEC initiatives. The Stakeholder Group meetings are an important forum for the Companies to get general feedback in all areas of the overall EEC initiative.

Subsequent to the approval of FEI's and FEVI's expanded EEC initiatives, the Province of BC has reaffirmed and strengthened its commitment to energy efficiency and conservation through the enactment of the *Clean Energy Act* ("CEA"). Energy efficiency and conservation, greenhouse gas emission reductions and the promotion of innovative clean energy development in BC are core themes in the CEA. The Companies' EEC proposals and funding requests are aligned with British Columbia's energy objectives as set out in the CEA.

This Appendix outlines the Companies' EEC funding requests for 2012 and 2013, and outlines in Section 5 below some additional changes that the Companies are proposing to:

a) expand customer eligibility for participation in EEC programs to include Interruptible Industrial customers of FEVI and to offer EEC programs to customers of FEW; and

b) modify the benefit-cost analysis by which EEC projects are assessed. The Companies believe that the requested funding for 2012 and 2013 is reasonable as it is well supported by the achievable potential identified in the Companies' recently completed Conservation Potential Review (discussed further below). The Conservation Potential Review summary is attached in Appendix K-2.

In the Companies' Long Term Resource Plan filed in 2010 ("2010 LTRP"), and in the regulatory proceeding related to the 2010 LTRP, the Companies had indicated that they believed that longer-term, sustained EEC funding was the optimum approach, and in response to one Information Request from the Commercial Energy Customers, had indicated that an EEC funding approval period of five years would be appropriate. Given that current EEC funding approvals expire at the end of 2011, and that this Revenue Requirement Application period is two years covering 2012 and 2013, the Companies have made a decision to proceed with requesting EEC funding approval to cover the years 2012 and 2013. The Companies will incorporate a longer-term funding request, and will incorporate the EEC scenario planning and impacts on demand forecasting, in the next Long Term Resource Plan, which FEU anticipates filing in 2013.

The remainder of this section is divided into the following parts:

- A discussion of the total requested funding for 2012 and 2013 (Section 2);
- A discussion of the budgeted EEC funding within the total funding envelope for previously approved "conventional" and Innovative Technologies program areas (Section 3);
- A discussion of the budgeted EEC funding within the total funding envelope for New Initiatives (Section 4); and
- A request for additional approvals related to customers of FEW, Interruptible Industrial customers on FEVI and benefit-cost analysis used to screen the Companies' EEC activity moving forward (Section 5); and
- Conclusion (Section 6).

2 REQUESTED FUNDING ENVELOPE FOR 2012 AND 2013

FEI and FEVI have had access to sufficient funding for 2010 activities, and the existing approvals ensure that there is sufficient funding for continued EEC activities in 2011. The approved funding for 2010 and 2011 is summarized in Table K-1 below.

Table K-1: Approved EEC Funding for 2010 and 2011

($ thousands)	**FEI**		**FEVI**	
	2010	**2011**	**2010**	**2011**
Residential, Commercial, Joint Initiatives, and CEO Programs	20,675	20,675	4,126	4,126
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**25,845**	**29,619**	**5,204**	**5,682**

A summary of the Companies' overall request for approval for each EEC program area for 2012 and 2013 can be found in Table K-2 below:

Table K-2: 2012 and 2013 Overall EEC Funding Request by Program Area

	2012 Proposed Funding ($000's)	2013 Proposed Funding ($000's)
	Total	**Total**
Previously Approved EEC Activity		
Conventional EEC Activity		
Residential	9,500	9,500
High Carbon Fuel Switching	2,000	2,000
Low Income	5,000	5,000
Commercial	14,500	14,500
Conservation Education and Outreach	5,000	5,000
Industrial	2,000	2,000
Subtotal - Conventional EEC Activity	***38,000***	***38,000***
Subtotal - Innovative Technologies inc. NGV	***11,500***	***11,500***
Subtotal - Previously Approved EEC Activity	***49,500***	***49,500***
New Initiatives		
Furnace Scrap-It program	**10,000**	**10,000**
Solar Thermal	**4,000**	**4,000**
TES for Schools	**11,000**	**11,000**
Subtotal - New Initiatives	***25,000***	***25,000***
Total Funding	**74,500**	**74,500**

The Companies' proposed increase in the total EEC funding envelope for 2012 and 2013 is based on:

- increases in areas of program activity in respect of which the Commission has already approved funding in Orders G-36-09, G-140-09 and G-141-09, discussed in Section 3 below, and
- budgets for, and activity relating to some new initiatives, discussed in Section 4.

While the funding requests represent an increase in EEC spending, the Companies have proposed a revised financial treatment for EEC spending in 2012 and 2013 (see Section 6.3.2 of the Application) that protects ratepayers in the event that the Companies are unable to spend the full amount within the funding envelope ($74.5 million/year). Under the proposed financial treatment, however, only $20 million per year of EEC spending is reflected in the 2012-2013 rate base and revenue requirements. $20 million was selected as the appropriate number since it aligns with the expenditures of approximately $17.7 million that the Companies were able to commit to EEC activity in 2010.

Actual EEC spending in 2012 and 2013 above $20 million per year will be recorded in non-rate base deferral account (attracting AFUDC) and will not commence recovery in rates until 2014. This revised financial approach is intended to ensure that customers only pay for actual EEC expenditures that are incurred during 2012 and 2013. Stakeholders will have the opportunity to comment on proposed budgets for upcoming years during the EEC Stakeholder Group meeting held in the fall of each year, once programs have been planned for the following year. Further, the Companies file the EEC Annual Report by March 31 each year, giving the Commission and stakeholders an additional opportunity to comment on proposed EEC activity, including planned budgets, for the upcoming year. For further details on how the EEC expenditures are treated for 2012 and 2013, please refer to Section 6.3.2.1 in the Application.

Consistent with the Commission's Decision in the EEC proceeding, the Companies propose that

- the overall funding level of $74.5 million be considered a level that would not be exceeded;
- the Companies will spend those funds only on approved Program Areas; and
- the Companies will retain their ability to re-allocate funds initially budgeted for one approved Program Area to another approved Program Area(s) and the FEU will report on funding transfers in their Annual Report.

The Companies believe that retaining the flexibility to allocate more of the approved funding to successful previously approved Program Areas and scale back other programs that are not performing as well as expected (subject to the requirements and constraints of the DSM Regulation) will continue to provide a strong results-based framework for the Companies' EEC initiatives. It will support the overall success and cost effectiveness of the EEC program portfolio as a whole. This approach and support from customer groups is outlined in the following passage from the EEC Decision on pages 41-42:

> *"Terasen summarizes its proposal for accountability mechanisms as follows:*
>
> *In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on*

program progress and obtain stakeholder Input on new programs and refinements to existing programs. Fifth, the Companies are proposing to develop many of the programs for the commercial sector and the DSM for Affordable Housing sector in conjunction with stakeholder advisory groups." (Terasen Argument, p. 39)

Intervenor Positions
BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)

BCOAPO argues that, should the Application be approved, an independent audit process should be Required with respect particularly to free ridership, attribution and redirection of funds. (BCOAPO Argument, p. 14)

Commission Determination
The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted,TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

Commission Panel directs that the annual EEC Report include the following:

- *TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*
- *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*
- *data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts."*

The incremental funding amounts in previously approved Program Areas compared to 2010/11 funding levels are discussed in Section 3 below. Within the previously approved Program Areas, the amounts budgeted for "conventional" activity are based on increases to budgets for the "conventional" EEC activity reported in the 2009 and 2010 Annual Reports (included as Appendix K-3 and K-4 respectively). 2009 and 2010 "conventional" EEC activity in turn was based upon the "bottom up" budgets that were developed for the 2008 EEC Application. The budgeted total amounts for "conventional" or non-Innovative Technology activity for 2010 and 2011 for FEI and FEVI were approximately $28.2 million and $29.7 million respectively. The Companies have budgeted for an increase for "conventional" EEC activity to $38 million/year for each of 2012 and 2013, which will allow the Companies to continue and expand the "conventional" EEC activities derived from the "bottom up" budgets developed for the original EEC Application. Further, the Companies have increased the Innovative Technology Program area request in 2012 and 2013 to $11.5 million. Budgeted EEC funding for previously approved EEC activity is the subject matter of the next section below.

3 FUNDING FOR PREVIOUSLY APPROVED EEC ACTIVITY

In Orders G-36-09, G-140-09 and G-141-09, the Commission has approved funding and activity for the following types of EEC programming: residential, commercial, industrial, joint initiatives, low income, conservation education and outreach and Innovative Technologies. The material below in Sections 3.1 and 3.2 describes increases to funding for this previously approved activity. For the purposes of organizing this write-up, activity for Natural Gas Vehicles has been included with Innovative Technologies under the heading of "Previously Approved EEC Activity" EEC programs. Although the Companies believe that is an accurate characterization, we wish to make clear that we recognize that this issue is being addressed in a separate regulatory process regarding the approval to expend EEC funds for activity relating to NGV, and that this issue remains outstanding at the time of filing.

3.1 EEC Funding for "Conventional" EEC Activity

For the purposes of this discussion, "conventional" EEC activity refers to all activity excluding Innovative Technologies and New Initiatives, and supports EEC activity related to residential (including low income), commercial and industrial customers. The Companies propose that the general areas of activity and programs for "conventional" EEC activity that were implemented in 2010 and 2011 be extended to cover the 2012 and 2013 time period, with budgeted increases to funding for most program areas. Descriptions of that activity and these programs for 2011 can be found in the Companies' 2010 Annual EEC Report, submitted to the Commission on March 31 2011, in sections 3, 4, 5, 6, 7, 8, 9 and 11. This 2010 EEC Annual Report is also included as Appendix K-4 to this Application. Table K-2 above outlines the Companies' budgeted funding levels for "conventional" EEC activity. The Companies have not yet commenced detailed program design for 2012 and 2013, and the subsequent development of individual program budgets for "conventional" EEC activity, but it could be expected to be very similar to the type of "conventional" activity outlined in the Companies' 2010 EEC Annual Report, with budgeted increases to funding levels to allow for the expansion of "conventional" EEC activity. It is the Companies' intention to develop program activity for 2012 over the course of 2011, and as in previous years, contemplated program activity for 2012 will be presented to the EEC Stakeholder group in the EEC Stakeholder meeting to be held in Fall 2011, and feedback from this group will be solicited and incorporated prior to any refinement to existing program or new programs launching in 2012.

The Companies' proposed budget for EEC programs in 2012 and 2013 reflects the following changes from the budgets established for previously approved "conventional" EEC activity in 2011:

- Consolidation of "Joint Initiatives" activity with "Residential" as all the activity funded in the Joint Initiatives program area undertaken to date has been for residential customers. Collaborative activity with other utilities and government is taking place in all other program areas; it is not, however, broken out into a separate funding category in these other program areas. It makes sense to align funding for collaborative activity for residential customers within the residential program area.
- An increase in budgeted funding for residential customers from approximately $5.2 million (for Residential and Joint Initiatives activity combined) to $9.5 million. The Companies anticipate that a Residential New Home Construction Program, a Domestic Hot Water Program and participation in such collaborative programs as LiveSmartBC will require a larger budget for EEC activity for residential customers than previously established. Residential customers form the bulk of the Companies' accounts, and programs aimed at these customers are very important in creating the "culture of conservation" that will be needed in order to achieve government's energy objectives.
- An increase in budgeted funding for high-carbon fuel switching to lower carbon fuels (e.g. Heating oil to natural gas) from approximately $1.5 million to $2 million. This activity would be aimed at residential and commercial customers, and would have the goal of moving these customers off propane and heating oil, and onto natural gas. It could also be aimed at moving customers onto alternative forms of energy, such as geoexchange with natural gas backup. This funding does not include fuel switching from electricity to natural gas.
- An increase in budgeted funding for low income customers from $3 million to $5 million. Activity in this particular area has good support from government and stakeholders.
- An increase in budgeted funding for conservation education and outreach from $3.5 million to $5 million as the Companies seek to expand activity around influencing conservation behaviours by British Columbians.
- An increase in budgeted funding for all industrial customers, regardless of whether they are on a firm or an interruptible rate, from $1.875 million to $2 million. This is a relatively new area of activity for the Companies, and it is anticipated that we will need time to gain knowledge and experience in this area, therefore only this modest increase is anticipated over the 2012 and 2013 period.

The above budgets for "conventional" EEC activity program areas form the basis for the overall funding request, but as indicated above the Companies are proposing to maintain the approach used since the 2009 EEC Decision whereby the Companies retain the flexibility to reallocate funding among any of the approved program areas as required to optimize the portfolio.

The Companies' recently completed Conservation Potential Review, the Summary for which is attached as Appendix K-2, found that the Most Likely Achievable Potential energy savings in the Residential, Commercial and Industrial areas of activity were 2.2 million GJ/year by 2015, and 10.3 million GJ/year by 2030. This represents significant opportunity for energy savings. In 2010, the Companies committed approximately $12.1 million in EEC funding to non-NGV EEC activity aimed at the Companies' Residential, Commercial and Industrial customers, for annual energy savings of 166,110 GJ/year. While the Companies are relatively new to this scale of EEC expenditure and activity, and the funds committed in 2010 included some "one-time" costs such as a DSM tracking system, it can be seen that in order to achieve the energy savings found to be available in the CPR, higher expenditures will be necessary. Hence, the Companies believe that the proposed increase in the EEC funding envelope for 2012 and 2013, reflecting budgeted increases in "conventional" EEC programs, is warranted.

3.2 Innovative Technologies, including Natural Gas Vehicles ("NGV")

In the 2008 EEC application, FEI and FEVI requested funding for Innovative Technologies since the utility is in a unique position to foster and further the deployment of forward looking low carbon technologies. On April 16, 2009, the Commission issued the EEC Decision approving funding for FEI and FEVI for 2009 and 2010 programs. While the Companies did not receive approval for expenditures for the Innovative Technologies Program Area as part of that application, the Commission directed the Companies to bring forward projects for consideration as they became more fully developed[1].

FEI and FEVI submitted their respective applications for 2010 – 2011 Revenue Requirements and Delivery Rates on June 15, 2009 and June 29, 2009, respectively, which proposed innovative technologies programs and expenditures in order to meet the Commission's directives in Order No. G-36-09. On November 26, 2009, the Commission issued Order No. G-141-09 and Order No. G-140-09 approving the Innovative Technologies programs and expenditures as listed in the Negotiated Settlement Agreement ("NSA") for both FEI and FEVI.

As part of their respective NSAs, the parties agreed that the Innovative Technologies Program Area will be managed by FEI and FEVI as a separate segment of the overall EEC portfolio and have a weighted total resource cost ("TRC") of 1.0 or more. A program manager was hired in the second quarter of 2010 to develop program design and framework for the non-NGV activity in the Innovative Technologies program area.

1 BCUC Decision in the matter of Fortis BC Energy Inc. and Fortis BC Energy (Vancouver Island) Inc. Energy Efficiency and Conservation Application, April 16, 2009, p. 26.

On January 14, 2011, FEI received Decision Order G-6-11 which granted interim approval of CNG Service for Waste Management to fuel their fleet of 20 garbage trucks. In this decision, the Commission raised a potential issue with respect to the use of EEC incentives for NGV vehicle reimbursement.[2] As discussed in the 2010 EEC Annual Report ("Report"), filed March 31, 2011, the Companies believe that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with previous Commission decisions[3] (Order Nos. G-36-09, G-141-09, and G-140-09), and that FEI has been open and transparent with stakeholders about EEC activities and expenditures, including the use of EEC incentives for NGV.[4] In the Report, the Companies requested that the Commission provide confirmation of the Companies' compliance with past orders without additional process, or alternatively, if the Commission was unable to provide this confirmation, the Commission provide its concurrence for the Companies to proceed with EEC incentive funding.

The Commission subsequently issued Order No. G-70-11 on April 20, 2011 which initiated an expedited process to review the appropriateness of the Companies' use of EEC funds as NGV incentives. The initial regulatory timetable is scheduled to conclude near the end of May 2011. Therefore the Utilities have developed their EEC funding request (and NGV volume and revenue forecast) in this RRA assuming that EEC incentive funding for NGV initiatives have been approved by the Commission.

In this RRA, the Companies have budgeted $11.5 million in 2012 and $11.5 million in 2013 to fund technologies with low market penetration including NGV, and enabling activities such as metering for these technologies, within the Innovative Technologies program area. Recognizing that the Commission's review process of incentive funding for NGV initiatives has not reached a conclusion at this time, the Companies have divided the Innovative Technologies section into two parts. The first section describes the $3 million funding contemplated ($1.5 million per year for each of 2012 and 2013) associated with non-NGV initiatives fostering the deployment of low carbon technologies. The second section describes the Companies' NGV funding contemplated of $20 million over two years ($10 million per year for each of 2012 and 2013). In each separate section the Companies provide some background on the programs, a description of the programs and its objectives, followed by a rationale of the funding amount contemplated by the Companies.

3.2.1 INNOVATIVE TECHNOLOGIES - NON-NGV INITIATIVES

Innovative technologies are solutions that the Companies can support through programs delivering energy reductions and savings to their customers for now and into the future. All programs within this program area are to foster and further the deployment of low carbon technologies. Those low carbon technologies are best described as being market ready but have little or no market penetration in BC. They can also be defined as emerging and/or

[2] Commission Order No. G-6-11, at page 5
[3] 2010 EEC Annual Report, at page 203
[4] 2010 EEC Annual Report, at page 216

enabling technologies. Some of these technologies include, but are not limited to, solar thermal domestic hot water systems, solar air systems, ground source heat pumps ("GSHPs"), hydronic systems, sterling engines, micro co-generation, and fuel cells. Hydronic systems can be classified as enabling technologies as they have the flexibility and potential to receive future energy from District Energy Systems ("DES").

The Innovative Technology programs pursue a number of objectives in order to support, review, and validate market-ready technologies. More specifically they focus on:

- Supporting local, provincial, and federal governments with climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of clean or renewable resources; and
- Evaluating market-ready technologies and conducting pilot studies and/or demonstration projects to validate manufacturer's claims about equipment and system performance, and energy efficiency.

The Companies are budgeting $3 million of the total requested funding envelope over 2 years ($1.5 million for each of 2012 and 2013) to support those objectives.

In 2010, the Companies committed $372,000 in funds to non-NGV Innovative Technologies activity, and we are estimating a commitment of approximately $715,000 in 2011. The 2011 commitments are almost double the amounts in 2010 due to the increased momentum of establishing and developing industry contacts, technology awareness and expertise, and further program design. The Companies expect this trend to continue into 2012 and 2013 as further market momentum for these technologies is gained.

The Innovative Technologies program area plays an integral role in the Companies' overall commitment to EEC activities, not only in reducing or replacing natural gas consumption with lower carbon technologies, but also in supporting the government's climate action goals. The Companies believe also that there is a strong need for measurement and verification of energy savings for these lower carbon technologies through conducting pilots and/or demonstration projects. The data from pilots can be used to validate manufacturer's claims about energy savings, help improve the quality and installation of future systems, and be used to understand and reduce market barriers. Traditionally costs to produce, distribute, install and monitor these technologies are higher due to a lack of market "scale" and require incentives for market transformation.

The Companies believe that continued funding for Innovative Technologies is critical in validating and piloting the energy saving performance of low carbon technologies for the development of future energy efficiency and conservation programs within the residential, commercial and industrial sectors.

3.2.2 INNOVATIVE TECHNOLOGIES - NATURAL GAS VEHICLE ("NGV") INITIATIVES

NGVs, which use liquefied natural gas ("LNG") or compressed natural gas ("CNG") as a heavy duty vehicle fuel (trucks and marine vessels), are considered part of the Innovative Technologies Program Area for two reasons. First, technologies used in NGV applications are market-ready, but can be classified as emerging technologies in the BC context as they have minimal market penetration in BC. Second, the Commercial NGV Demonstration program achieves GHG emissions reductions by displacing high-carbon diesel fuel with low-carbon natural gas. Through this program, the Companies (FEI and FEVI) provide funding to offset, in whole or in part, the incremental vehicle cost difference between an NGV compared to its diesel equivalent. The Companies' EEC request includes $10 million in 2012 and $10 million in 2013 to fund its NGV initiatives within the Innovative Technologies Program Area. Based on information provided by equipment vendors, the capital cost premiums associated with CNG and LNG vehicles are approximately:

- CNG Vocational truck (refuse, waste hauler) - $27,000 - $45,000
- CNG Transit bus - $50,000 - $70,000
- LNG Class 8 tractor - $80,000 - $90,000
- LNG Marine vessel - $3 - $4 million

In 2012 and 2013 the Companies anticipate a funding level which ranges from 80 percent to 100 percent of the incremental cost differential.[5] An exact percentage has not yet been determined and its timing will likely depend upon level of adoption of each vehicle category and the capital cost premium. The Utilities believe that capital cost premiums will decrease as NGV adoption increases in BC. Future adjustments to the funding levels will be assessed as NGV adoption occurs.

The Utilities have used these assumptions to calculate the approximate number of vehicles which could be funded with $10 million in 2012 and $10 million in 2013.[6] The potential number of vehicles which could be incented with this amount is presented in the volume forecast in Appendix I of this Application. FEI anticipates market adoption in vocational trucks, Class 8 tractors and buses to occur 2012 and 2013, with one marine vessel forecast for 2013. FEI also notes that a lag may exist between when vehicles are purchased, delivered and ready for

[5] Funding levels during 2010 and 2011 have ranged from 80 percent – 100 percent of the incremental cost between NGVs and its diesel equivalent. Future funding may be lower than 80 percent depending upon the level of NGV adoption and capital cost premium.

[6] At this time, FEI offers incentive funding ranging between 80 – 100 percent of the incremental cost. This reimbursement level may decrease in the future as NGV adoption increases and cost premiums decrease, however the exact amount and date is unknown at this time.

fuelling service. This means load additions do not necessarily occur in the same year as incentive payments are issued.

The growth of the NGV refueling business is inherently reliant upon the adoption of NGVs in our service territory and the Utilities believe that the adoption of NGVs in our service territory depends upon the continued availability of these EEC incentives for NGV adoption. The Utilities wish to make clear that there is no conditional connection between EEC incentives for NGV and the need for the Utilities to also build and operate the NGV refueling stations, other than that the availability of both as options are required in order to see the NGV adoption required to provide meaningful and material benefit to our existing customers. Further, regardless of who provides the fueling service the benefits of increased throughput across the FEI system for CNG and LNG will benefit existing customers.

For additional information on the NGV forecast and potential benefits of our NGV initiatives, please refer to Appendix I of this Application.

4 NEW INITIATIVES

The Companies' proposed EEC funding envelope for 2012 and 2013 includes funding for several new programs that have not yet been considered by the Commission and do not meet the cost effectiveness test requirements currently applicable to the Companies' EEC programs. Changes to the cost effectiveness tests such as employing the Societal Cost Test ("SCT") rather than the TRC or amendments to the DSM Regulation will be required in order for these new initiatives to meet cost effectiveness thresholds or other stipulations of the DSM regulation. The SCT is discussed in Section 5.2.2 below. In other words, the Companies cannot pursue these initiatives in the absence of a change to employing the Societal Cost Test or to the DSM Regulation. The reason that funding for new initiatives has been included in the overall requested funding envelope is that FortisBC has been made aware that the Ministry of Energy and Mines is considering developing amendments to the DSM Regulation and the program proposals below are intended to comply with possible amendments. The final form of DSM Regulation amendments, if any, and the timing of when they occur, is subject to the approval of the Minister of Energy and Mines. The Companies believe that it is most efficient and logical to include a request for funding in this application, rather than having to reapply for funding for New Initiatives if and when any changes to the DSM Regulation come into effect.

It is possible to address this funding now, as part of this RRA, because the proposed changes to the regulatory treatment of EEC funding in 2012 and 2013 will ensure that customers will not pay for the costs of these new initiatives in rates unless the programs proceed and the funds are actually spent. The Companies have also included a request (discussed in Section 5.2.2 below) to adopt the SCT for all EEC activity, including for these New Initiatives.

4.1 Furnace Scrap-It Program

The Companies requested EEC funding includes a budget of $10 million per year for each of 2012 and 2013 for a Furnace Scrap-It Program. Supporting energy bill reductions for families and small businesses throughout the FortisBC service territory, this proposed program would replace about 10,000 furnaces per year with super-efficient ones. Although many standard and mid-efficient furnaces are theoretically beyond their rated operating life (~20 years), they continue to function and owners are not upgrading them due to a poor payback period on the purchase of a new furnace (~20 years at current rates). However, the owners would have to replace the furnaces in 5-10 years anyway (and incur the full cost). As such, this program would provide an incentive for early replacement, resulting in short-term cost savings and emission reductions.

It is estimated that there are 560,000 standard- and mid-efficiency furnaces in British Columbia. In 2009, the total furnace shipments to BC were 36,000, although a sizable proportion of those are for new construction. Assuming two-thirds of those furnaces shipped were replacement, it would take 23 years for British Columbians to replace their inefficient furnaces, a lost opportunity for financial savings for homes and small businesses.

The LiveSmart BC: Efficiency Incentive Program is expected to provide rebates for about 3,900 super-efficient furnaces in 2011. The Furnace Scrap-It program would support an additional 10,000 furnaces per year, some of which might go through the LiveSmart program as well. This would accelerate the replacement of British Columbia's inefficient furnaces by about 50 percent.

There are several "non-energy benefits" of a furnace replacement that are not currently considered in the approved DSM evaluation models when evaluating programs. The Companies have outlined in Section 5.2.2 below a proposal to move to the SCT to evaluate all EEC activity. Such a change would allow the Companies to offer this program to our customers. As can be seen in the Residential section of the CPR Summary attached as Appendix K-2, space heating accounts for 80 percent of the residential energy savings, and the largest contributor to this space heating energy savings is a furnace early retirement initiative. The Companies' requested EEC funding includes a budget of $10 million per year for each of 2012 and 2013, to fund approximately 10,000 furnace retirements with an incentive of $1000 per participant. For the reasons described above, the Companies believe that the budgeted amount of funding is justified and should be reflected in the overall funding envelope ultimately approved by the Commission.

4.2 Solar Thermal

The Companies' requested funding includes a budget of $8 million over the next 2 years ($4 million for 2012 and $4 million for 2013) for Solar Thermal. This program offers energy source reductions from natural gas to solar for domestic hot water for residential and commercial applications, and solar for space conditioning preheat for commercial and industrial applications. Natural gas would still be part of the picture as a backup fuel source. It also supports the government's climate action goals and policies focused on fostering the development of market-ready technologies that promote energy conservation and efficiency and the use of renewable resources. Both of those initiatives will reduce natural gas consumption and carbon emissions.

There is a strong need for a utility program in this area, as Natural Resources Canada's EcoEnergy for Renewable Heat program and SolarBC's Residential program offering incentives for solar thermal were discontinued effective December 31, 2010. Budgets at other levels of government (provincial and municipal) are inadequate to provide the kind of scale needed to start the market transformation effort for solar thermal as customers are not willing to absorb the high upfront capital cost for the energy bill savings and other benefits expected. The SolarBC Residential program offered incentives to encourage 540 households across BC to install solar hot water which resulted in 4,353 GJ saved every year and annual GHG emission reductions of 94 tonnes of CO_2. 240 or (54 percent) of all the residential installations since 2008 occurred in 2010. NRCan's EcoEnergy for Renewable Heat program also proved to be a success, funding over $20.5 million for 1,268 commercial solar thermal hot water systems and industrial solar for space conditioning preheat systems throughout Canada. 514 or (41 percent) of all the commercial and industrial installations since 2007 occurred in 2010. The results of both the SolarBC Residential and NRCan's EcoEnergy for Renewable Heat program indicate an active industry interest for solar thermal and resulted in an increased uptake percentage each year that those programs were available. The Companies believe that those program results indicate a strong demand for solar thermal within the residential, commercial and industrial sectors to support the $8 million that the Companies have budgeted. The Companies also believe that it is essential for market transformation to continue the positive momentum that has been gained over the last few years through those programs with developing its market share, associated jobs and economic benefits.

Solar thermal projects fail the Total Resource Cost ("TRC") test, due to the high incremental cost of solar equipment, and the prevailing low cost of natural gas. Consequently, solar thermal programs will not be able to proceed in any material fashion in the absence of the application of the Societal Cost Test as requested by the Companies. In the case of solar thermal, using a deemed adder for non-energy benefits of 30 percent, as proposed in Section 5.2.2 below, would effectively capture such non-energy benefits as job creation, and environmental attributes.

For the reasons described above, the Companies believe that the budgeted amount of funding for Solar thermal is justified and should be reflected in the overall EEC funding envelope ultimately approved by the Commission.

4.3 Thermal Energy Services for Schools

FortisBC is proposing a $22 million incentive program for geoexchange and energy efficiency retrofits in up to 260 schools over two years. The TES for Schools program would provide capital incentives for state-of-the-art low carbon energy systems such as geoexchange systems, high-efficiency boiler upgrades, as well as educational energy monitoring equipment. These state-of-the-art low carbon energy systems continue to incorporate natural gas as a critical energy input, whether as the primary component or as a back-up and peaking energy source.

The need to replace worn out equipment (such as central boilers, individual rooftop air-handling units, and ancillary equipment) is urgent for many schools across BC, but the incremental costs are a major barrier for schools to proceed with replacing their energy systems. In addition, schools are challenged with compliance with government legislation to become carbon neutral via reduction in carbon emissions and/or through the purchase of carbon offsets. Faced with limited budgets and constraints on capital and debt, the ability of school districts to achieve these goals is limited.

To foster a competitive market, incentives would be available for projects using a third party ownership model and those owned and operated by school boards. Incentive levels are structured to ensure positive economics for participating school districts, while maximizing ratepayer value. As the highly efficient geoexchange systems do not meet the current cost-effectiveness test due to high incremental capital costs, the budgeted $22 million in program spending will employ a pooled approach in the cost-effectiveness evaluations for each school district, which aims to minimize GHG emissions while ensuring economical solutions through the selection of the optimal combination of technologies to fit within both operating and capital budget constraints. This approach enables a major increase in the total number of school retrofits and expands the share of geoexchange installations, while keeping incentives to 50 percent or below of a school district's combined equipment capital costs.

The scope of this program has been restricted to schools to address a clearly defined financial need, to provide benefits that target BC families, and to provide important educational and training opportunities about energy efficiency and environmental stewardship for present and future generations of students, which benefits would be among those captured using the 30 percent proposed deemed adder for non-energy benefits in the Societal Cost Test, as outlined in Section 5.2.2 below.

5 ADDITIONAL APPROVALS REQUESTED

In addition to funding approvals, in the EEC Decision the Companies received a number of additional approvals related to the principles guiding EEC activity, how programs are to be evaluated, and oversight mechanisms. The Companies are proposing some changes to some of these guiding principles discussed in this section, but by and large the Companies are proposing no changes to the existing EEC framework.

5.1 Elements of Existing EEC Framework to be Retained

Most aspects of the existing EEC framework continue to make sense going forward. The key approvals previously granted to which the Companies are proposing no change are as follows:

- The Commission approves an overall funding envelope comprised of a portfolio of approved program areas. Consistent with that notion, the Companies will continue to have the ability to move funds between programs and program areas to optimize the portfolio;
- Continue to use the portfolio level approach to benefit-cost analysis such that the overall portfolio including all EEC-funded activity should have a benefit-cost result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the portfolio using the Societal Cost Test as discussed in Section 5.2.2 below);
- Continue to evaluate the Innovative Technologies portfolio of activity on a separate segment of the overall portfolio, with a weighted average benefit-cost test result of 1.0 or greater. (The Companies are proposing a change to measure cost-effectiveness of the Innovative Technologies portfolio using the Societal Cost Test, as the Companies are proposing in Section 5.2.2 below that the Societal Cost Test be used for all EEC activity, including Innovative Technologies);
- Continue to be able to offer programs and measures with a benefit-cost result of less than 1.0, but provide information in annual reporting as to why the program should continue, including information on any environmental or social or other goals supported by the program or measure;
- Continue to use the approved accountability mechanisms that the Companies have put in place, that is the EEC Stakeholder group, and EEC Annual Report, which offer the Commission and Stakeholders the opportunity to comment on proposed program activity. The EEC Annual Report includes a supporting rationale for funding transfers between approved program areas and funding transfer impacts. It also includes reporting on the benefit-cost analysis, and justification for continuing with programs and measures with a benefit-cost result of less than 1.0.
- Continue to be guided by the “EEC Program Principles” put forward originally in Section 5 of the EEC Application; and
- Continue to capitalize the approved EEC expenditure to a regulatory deferral account, and to amortize deferral account balances for a period of up to ten years. The regulatory treatment for the first $20 million per year of EEC spending in 2012 and 2013 is the same as the treatment for EEC spending in 2011 and before (as approved by BCUC Order No. G-36-09). The proposed regulatory treatment for 2012 and 2013 EEC spending in excess of $20 million per year, whereby these amounts are recorded in a non-rate base deferral account and recovery in rates is not commenced until 2014, constitutes a small departure from this treatment. The Companies have proposed this change to recognize the variability in customer participation that may occur in the forecast period and to mitigate the risk of recovery in rates for budgeted EEC spending that does not actually occur.

Further, the Companies' EEC activity will continue to comply with the requirements for adequacy as laid out in the DSM Regulation.

5.2 Proposed Changes to Existing EEC Framework

The Companies are proposing few changes to the existing approved EEC framework. The proposed changes, discussed in the remainder of this section, are:

- Expand all EEC programs eligibility to customers of FEW and to offer the Interruptible Industrial program to customers of FEVI; and
- Move to use of the Societal Cost Test as the primary means of evaluating the cost-effectiveness of the Companies' EEC activity.
- Include spillover in "Net-to-Gross estimates of program effects

The Companies believe that these changes will make EEC funding more widely available to customers, and will help to make the EEC program more effective.

5.2.1 ELIGIBILITY EXTENDED TO FEW AND INDUSTRIAL INTERRUPTIBLE CUSTOMERS OF FEVI

The Companies are proposing the following:

- To extend eligibility for EEC program participation to customers of FEW in order to comply with Order G-138-10.[7];
- To expand eligibility for participation in programs to Interruptible Industrial customers of FEVI; and
- In the Companies' 2010-2011 Revenue Requirements proceeding, the Companies did not apply for funding for EEC activity for Interruptible Industrial customers of FEVI, as the Companies had very little experience with Industrial DSM and wished to hire an Industrial Program Manager and start to develop an Industrial strategy based on FEI's larger industrial customer base. That Industrial Program Manager is now in place, and the Industrial strategy developed. Thus, the Companies feel it is now appropriate to expand eligibility for participation in EEC activity to Industrial customers of FEVI. The Industrial strategy can be found in Section 9.1.5 of the Companies' 2010 EEC Annual Report, which is included in Appendix K-4.

[7] As per Commission's Reasons for Decision, Order No. G -138-10, as part of FEW (formally referred to as TGW) 2010-2011 RRA, indicating concerns about the lack of DSM initiatives in TGW's Application, and directing TGW to develop plans for DSM programs, consistent with British Columbia's energy objectives, in the next revenue requirements application.

5.2.2 ADOPTION OF THE SOCIETAL COST TEST AS THE PRIMARY COST-EFFECTIVENESS SCREEN

The Companies are proposing that the Societal Cost Test be used as the primary cost-effectiveness screen for all of the Companies' EEC activity, including "conventional" and Innovative Technologies, incorporating the following three proposed changes:

- The use of a social discount rate of 3 percent, rather than the Companies' weighted average cost of capital;
- The use of the ceiling price put forward by the Companies for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas; and
- The use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity such as job creation and improved human health.

The following will discuss the rationale of the use of the Societal Cost Test in general, before discussing these three proposals in particular.

The Companies have to date employed the TRC test as the primary cost effectiveness screen in establishing EEC programs. While the Terasen Utilities proposed and obtained approval for a portfolio-level TRC approach, the Companies' EEC activity is increasingly expected to support government policy. Government policy incorporates wider goals than just energy savings reflected in the TRC test, such as achieving GHG reductions, or providing programs for low-income customers.

As stated in the 2010 LTRP, we believe that the current cost-benefit criteria for some programs limit the benefits that can be delivered for emission reductions and for certain customer groups such as low income earners.[8] In particular, the Companies' new initiatives described in Section 4 above would not be considered to be cost-effective under the TRC test. The Companies believe, however, that all these programs have merit and that the TRC test does not accurately value the benefits of these initiatives. Continued use of the TRC test has the potential to preclude programs that offer benefits to the public, including customers.

In the 2008 FEI-FEVI EEC Application filed May 28, 2008, the use of the Societal Cost Test was supported by intervenors, as recorded in the Reasons for Decision for Order No. G-36-09 (p. 34). In its Reasons for Decision, the Commission noted the following with respect to the Societal Test:

> *"The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognizing that societal factors have significance, the Commission Panel views many of these factors as being*

[8] 2010 LTRP, page 115.

rather subjective and difficult to measure, The Commission Panel also takes note of the DSM Regulation…requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective.“

First, FEU agrees that the Societal Cost Test factors have significance. FEU's fundamental position is that these significant factors must be given some recognition, otherwise some EEC programs will not be permitted to proceed despite offering benefits to the public, including customers.

Second, while FEU agrees that the societal factors may be subjective and difficult to measure, the Companies have set out specific proposals to overcome the difficulties. As explained below, the Companies are proposing a 30 percent deemed adder, which recognizes the significant societal benefits of EEC programs.

Third, the DSM Regulation does not restrict the Commission's ability to use the Societal Cost Test. Section 4(2) of the DSM Regulation only requires the use of the TRC test with respect to demand-side measures specified in section 3(a) of the DSM Regulation, which refers to "a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption". Further, while the DSM regulation requires that the TRC be used for these particular demand-side measures, it does not require that it be the only factor. To the contrary, section 4(2) specifically mandates that the Commission use the TRC "in addition to conducting any other analysis the commission considers appropriate." The Commission is therefore free to use other analysis in considering the cost-effectiveness of even the demand-side measures for low-income households.

The Companies are thus requesting approval to move toward a Societal Cost Test in order to capture some of the benefits associated with the broader goals of DSM. The Companies' particular proposed changes to the benefit/cost screen currently used for EEC activity are discussed below.

5.2.2.1 Use of a 3 percent Social Discount Rate

The discount rate currently being used to evaluate EEC programs is based on the Companies' weighted average cost of capital. Discounting at this rate is not appropriate as energy savings occurring beyond about the 7th year after a measure has been installed are accorded very little value, even though savings may accrue for up to 50 years in the case of some measures such as highly efficient new construction, and building envelope retrofits.

The use of the current discount rate understates the value of EEC measure as 100 percent of the cost of a measure is included in the benefit-cost analysis, but not all of the benefits, since much of the future benefits are so heavily discounted they have no material impact on the TRC result. A more robust analysis would more closely match the benefits of a measure to the costs of the measure. The Companies are therefore proposing the use of a social discount rate of 3 percent to more closely align the benefits associated with a measure with the costs.

5.2.2.2 Use of the Ceiling Price for Biomethane as the Avoided Cost of Gas

The avoided cost of gas currently being used is based upon a forward projection of market costs for conventional fossil fuel-based natural gas. It is used to calculate the "benefit" side of the equation in cost-effectiveness analysis of EEC activity. Because the avoided cost currently being used is based upon market prices, which are subject to volatility and fluctuation over time, the amount of EEC activity that is deemed "cost-effective" also fluctuates with this volatility. This is not a desirable situation given that the Companies' ultimate goal for much of its EEC activity is market transformation, which requires sustained, long-term utility activity in support of increasing market penetration of efficient technology. Moving to the ceiling price for biomethane, which is derived from an efficiency-adjusted cost of "green" electricity, more completely captures the environmental benefits of DSM. Biomethane and "green" electricity are considered to be zero-emission sources of energy; DSM activity is also zero-emission. Thus, using the avoided cost of biomethane or an efficiency-adjusted cost for "green" electricity in the benefit-cost test recognizes the typically higher cost of "green" energy sources such as biogas, electricity and DSM.[9]

5.2.2.3 Use of a "deemed adder" of 30 percent for Non-Energy Benefits

While societal factors/non-energy benefits may be subjective or difficult to measure, they have significance. Not including any benefit for these factors, therefore paints an unduly negative picture of the results of EEC activity. Alongside energy savings, EEC activity creates jobs, offers the opportunity for energy bill savings to be injected back into the economy by customers in the form of other spending, conserves other resources such as water, and can increase human health, comfort and productivity. While the financial value of these additional benefits may be challenging to quantify precisely so that this value can be included in a benefit-cost test, ignoring their value is not appropriate. Thus, the Companies are proposing a "deemed adder" of 30 percent for non-energy benefits be included in the benefit-cost analysis of the Companies' EEC activity. The deemed adder for non-low income EEC activity being proposed by the Companies is aligned with the deemed adder of 30 percent to account for non-energy benefits of low-income programs found in the DSM Regulation for EEC activity for low-income customers.

5.2.3 RECOGNITION OF SPILLOVER EFFECTS IN THE NET-TO-GROSS RATIO

In order to present a more complete view of program impacts, the Companies propose to include in the Net-to-Gross ratio the energy savings attributable to customers undertaking an

9 More information about the ceiling price for biogas can be found on pp 76-77 of FEI's Biomethane Application, dated June 8, 2010.

energy-saving activity who do not participate in a program. This effect is known as "spillover." Both the Net-to-Gross ratio and Spillover are defined below.

> **Net-to-gross ratio (NTG):** The NTG can be a significant driver in the results of TRC, PACT, RIM, and SCT. The NTG adjusts the impacts of the programs so that they only reflect those energy efficiency gains that are the result of the energy efficiency program. Therefore, the NTG deducts energy savings that would have been achieved without the efficiency program (e.g., "free-riders") and increases savings for any "spillover" effect that occurs as an indirect result of the program. Since the NTG attempts to measure what customers would have done in the absence of the energy efficiency program, it can be difficult to determine precisely. [10]
>
> **Spillover (simple definition):** Spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program.[11]

Although estimating spillover effects is as difficult to determine as estimating free rider effects, it is important to attempt to capture additional energy savings from spillover in order to achieve a more balanced view of program impacts. Thus, the Companies are seeking approval to include spillover effects in Net-to-Gross calculations.

6 CONCLUSION

Subsequent to the approval of FEI's and FEVI's expanded EEC initiatives in 2009, the Province of BC has reaffirmed and strengthened its commitment to energy efficiency and conservation through the enactment of the *Clean Energy Act* ("CEA"). Energy efficiency and conservation, greenhouse gas emission reductions and the promotion of innovative clean energy development in BC are core themes in the CEA. The Companies' EEC proposals and funding requests are aligned with British Columbia's energy objectives as set out in the CEA. The Companies believe that the requested funding for 2012 and 2013 is reasonable as it is supported by the achievable potential identified in the Companies' recently completed Conservation Potential Review.

[10] Source: Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers- Nov 2008
[11] Ibid

Appendix K-2

CPR SUMMARY REPORT

Marbek

Conservation Potential Review – 2010 FortisBC

Residential, Commercial and Industrial Sectors: Energy-efficiency, Alternate Energy & Customer Behaviour Opportunities (2010-2030)

Summary Report

Final Draft

Submitted to
FortisBC

Submitted by
ICF Marbek

In association with
Habart Associates
The Cadmus Group
Environ

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222 Somerset Street West, Suite 300
Ottawa, Ontario, Canada K2P 2G3
Tel: +1 613 523-0784
Fax: +1 613 523-0717
info@marbek.ca
www.marbek.ca

Table of Contents

List of Exhibits

1 Introduction

1.1 Objectives

This Conservation Potential Review (CPR) provides FortisBC with a comprehensive planning document that the company can use on an ongoing basis to:

- Develop a long-range energy-efficiency strategy
- Design and implement energy-efficiency programs
- Assess the impact of energy-efficiency programs on both peak and annual loads
- Set annual energy-efficiency targets and budgets.
- Determine contribution energy-efficiency programs can make towards meeting greenhouse gas (GHG) reduction targets

However, it should be emphasized that this report does not aim to either set specific program targets or provide program design.

1.2 Scope

Sector Coverage: The study addresses three sectors: Residential, Commercial and Industrial. In contrast to the 2006 CPR, which excluded FortisBC's (then Terasen Gas's) 300 largest manufacturing accounts, this CPR includes all of FortisBC's customers.

Geographical Coverage: The study results are presented for the total FortisBC service region and for the five service areas of: Lower Mainland, Vancouver Island, Whistler, Northern Interior and Southern Interior.

Study Period: The Base Year for this study is calendar year 2010. The time period covered by this study is to 2030, with milestones at the intervening years of 2015, 2020 and 2025.

Technologies: The study addresses energy-efficiency, customer behaviour and alternative energy options such as renewables and combined heat and power technologies.

Relation to Previous B.C. CPRs: This study builds on the substantial body of information and modelling work prepared in previous CPR studies conducted for FortisBC (then Terasen Gas) (2006) and BC Hydro (2007). The 2006 FortisBC study was intended to mesh with the BC Hydro study from 2007 and therefore included all customers of either utility, not just FortisBC customers. This study includes only FortisBC natural gas customers because this permitted the study to make better use of the recently completed energy end-use studies.

1.2.1 *Data Caveat*

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future economic growth and customer willingness to implement new energy-efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by FortisBC and are based on best available information, which in many cases includes the professional judgement of the consultant team, FortisBC personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout the report.

1.3 Study Organization

The study has been organized into the following areas:[1]

- **Three individual sector reports** (Residential, Commercial and Industrial) that provide an assessment of the technical opportunities for more efficient use of natural gas within each sector. A summary report will bring together the findings of all three sectors.

- **A commercial end-use survey (CEUS)** that provides insight into current natural gas equipment efficiency levels, fuel share and annual consumption levels within key Commercial sub sectors. The CEUS results were used to refine the Commercial sector building archetypes employed in the assessment of technical opportunities.

- **An options paper** that outlines alternative approaches to the assessment of cost-effective levels of DSM activity outside of the California Standard Practice tests.

1.4 This Report

This report brings together the findings of the Residential, Commercial, and Industrial sectors, together with an estimate of the net job creation and other economic effects attributable to the achievable efficiency results within the three sectors. The report is organized as follows:

- **Section 2** presents a summary of the total study results, including the total Base Year, Reference Case, Economic and Achievable Potential results for the Residential, Commercial, and Industrial sectors.

- **Section 3** presents a summary of the Residential sector results for the study period 2010 to 2030.

- **Section 4** presents a summary of the Commercial sector results for the study period 2010 to 2030.

- **Section 5** presents a summary of the Industrial sector results for the study period 2010 to 2030.

- **Section 6** presents a summary of the economic impacts associated with the identified Achievable Potential savings.

[1] **Note:** A separate Customer Preferences study was prepared in parallel with this CPR. The two studies were, however, implemented in a coordinated manner and the results of the Customer Preferences study contributed to the results of this CPR.

1.5 Definitions

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that all readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" energy is currently used in the existing Residential, Commercial, and Industrial sectors. Creation of the Base Year required the development of profiles of natural gas use within each sector, sub sector and service area.

Reference Case (includes Natural Conservation) The Reference Case estimates the expected level of natural gas consumption that would occur over the study period in the absence of new demand side management (DSM) program initiatives. It provides the point of comparison for the subsequent calculation of "Economic" and "Achievable" savings potentials. Creation of the Reference Case required the development of detailed profiles for new buildings and plants in each of the sub sectors, estimation of the expected stock growth, estimation of the likely impacts of new building, appliance and equipment standards and, finally an estimation of "natural" changes affecting energy consumption over the study period.

Technology Assessment Energy-efficiency, customer behaviour, and alternative energy options were identified that met the criteria, as outlined above, in the study's scope. Technology cost and performance data were compiled relative to the base line technology and the measure total resource cost (TRC) was calculated for each option.

Measure Total Resource Cost The conventional measure TRC calculates the net present value of energy savings that result from an investment in an efficiency, behaviour, or alternative energy technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating and maintenance (O&M) costs. This calculation includes, among others, the following inputs: the avoided natural gas and electricity supply costs, the life of the technology, and the selected discount rate, which in this analysis has been set at 7.38% for most of the regions and 6.87% for Vancouver Island. Societal impacts are not included in the TRC.

Economic Potential Forecasts The Economic Potential Forecast is the level of energy consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective, from FortisBC's perspective, when using lifecycle costing with the long-run avoided cost of new natural gas supply. All the energy-efficiency, behaviour, and alternative energy options included in the technology assessment that had a positive measure TRC, which is the conventional DSM screen, were incorporated into the Economic Potential Forecast.

Two Economic Potential Forecasts were prepared 1) energy efficiency and alternative energy, and 2) behaviour.

Achievable Potential The Achievable Potential is the proportion of the savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all the energy-efficiency/alternative energy or behaviour options that meet the criteria defined by the Economic Potential Forecast. The results are presented as a range, defined as *most likely* and *aggressive*.

Estimates provided were developed in a workshop involving FortisBC energy-efficiency program personnel, trade allies, selected external experts and the consulting team.

Peak Day Load Impacts Load factors provided by FortisBC were used to derive peak day load impacts from the energy consumption values contained in each of the potential estimates noted above.

Residential Customers For the purposes of this study, residential customers are categorized under Rate 1 in most of the FortisBC service region, RGS in the Vancouver Island region, and RES SGS1/SGS2 in the Whistler region. Multi-storey apartment and strata buildings are addressed in the Commercial sector report.

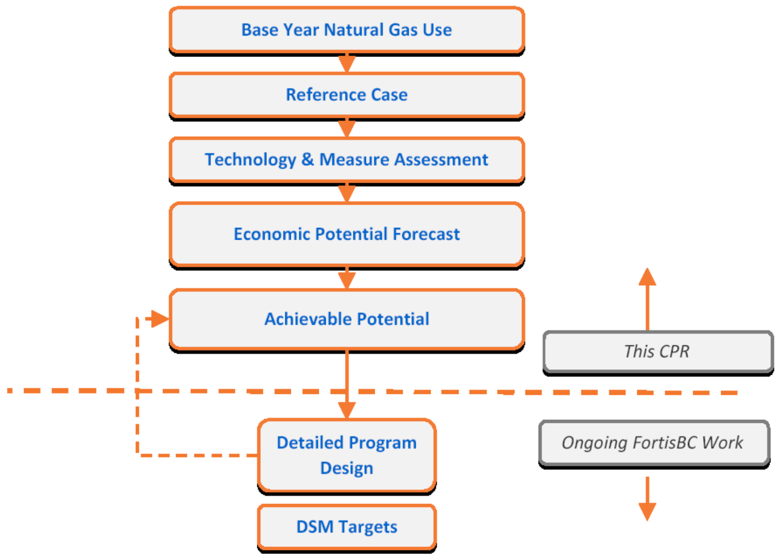
Commercial Customers For the purposes of this study, commercial customers are categorized under Rates 2, 3, 23, 22, 25, and 27 in most of the FortisBC service region. Note that this study classifies “Commercial” and “Industrial” facilities based on building/plant attributes, as represented by NAICS codes. This approach, which is consistent with CPR best practices throughout North America, is in contrast with the rate class approach employed by FortisBC. The rate-based approach tends to classify customers based on annual sales volumes. For example, light manufacturing facilities are typically included within FortisBC’s small commercial rate class; however, in this study these customers are included in the Industrial sector. Commercial customers also include multi-storey apartment and strata buildings.

Industrial Customers For the purposes of this study, industrial customers are categorized under Rates 2, 3, 5, 7, 23, 22, 25, and 27 in most of the FortisBC service region.

1.6 Overview of Approach

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps, as outlined in Exhibit 1. At the completion of each step, FortisBC reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step.

Exhibit 1 Major Study Steps



A summary of these steps is presented below.

Step 1: Develop Base Year Calibration Using Actual FortisBC Sales Data

- Compile and analyze available data on British Columbia's existing building stock and plants.
- Develop detailed technical descriptions of the existing building stock and plants.
- Undertake computer simulations of energy use in each building type and compare these with actual building billing and audit data.
- Compile actual FortisBC billing data.
- Create sector model inputs and generate results.
- Calibrate sector models results using actual billing data.

Step 2: Develop Reference Case

- Compile and analyze building design, equipment and operations data, and develop detailed technical descriptions of the new building stock.
- Develop computer simulations of energy use in each new building type.
- Compile data on forecast levels of building stock growth and "natural" changes in equipment efficiency levels and/or practices.
- Define sector model inputs and create forecasts of energy use for each of the milestone years.
- Calibrate with FortisBC load forecast.

Step 3: Develop and Assess Energy-efficiency, Alternate Energy and Behaviour Measures

- Develop list of energy-efficiency, alternate energy and customer behaviour measures.
- Compile detailed cost and performance data for each measure.
- Identify the baseline technologies employed in the Reference Case.
- Compile FortisBC and BC Hydro economic data on current and forecast costs for new supply of natural gas and electricity generation.
- Determine the measure TRC for each energy-efficiency and fuel choice option.

Step 4: Estimate Economic Energy-efficiency, Alternative Energy Potential and Behaviour Measures

- Screen the identified energy-efficiency and alternative energy measures from Step 3 against the economic data.
- Identify the combinations of energy-efficiency measures and building types where the measure TRC is positive.
- Apply the economically attractive energy-efficiency measures from Step 3 within the energy-use simulation model developed previously for each building type.
- Determine annual natural gas consumption in each building and plant type when the economic efficiency measures are employed.
- Compare the consumption levels when all economic efficiency and alternate energy measures are used with the Reference Case consumption levels and calculate the natural gas consumption impacts.

Step 5: Estimate Achievable Savings Potential

- “Bundle” the energy-efficiency, alternative energy and customer behaviour options identified in the Economic Potential Forecast into a set of Actions.
- Create “Action Profiles” for each of the identified Actions that provide a high level rationale and direction, including target technologies and sub markets as well as key barriers and a broad intervention strategy.
- Review historical Achievable program results and prepare preliminary Action Assessment Worksheets.
- Consult with FortisBC personnel, review preliminary estimates and reach general agreement on *most likely* and *aggressive* range of Achievable Potential.

Step 6: Estimate Peak Day Load Impacts of Economic and Achievable Savings Potential

- Annual energy decreases/increases contained in each of the energy-efficiency/fuel choice scenarios were converted to average daily values based on annual load profile data provided by FortisBC.
- Load factors that correlate “average” to “peak” consumption were provided by FortisBC for each rate class and service area.
- Peak day load impacts were calculated for each of the energy-efficiency and fuel choice scenario results by applying the above load factors.

2 Summary of Total Study

2.1 Total Natural Gas Savings Potential

The study findings confirm the existence of significant remaining cost-effective natural gas DSM opportunities in the Residential, Commercial, and Industrial sectors within FortisBC's service area.

Exhibit 2 and Exhibit 3 summarize the total combined natural gas savings for the Residential, Commercial and Industrial sectors that have been identified in each of the individual sector technical reports. Selected highlights include:

- In the Reference Case, total natural gas consumption in the total FortisBC service area decreases from approximately 167.6 million GJ/yr. in 2010 to approximately 162.6 million GJ/yr. by 2030, a decrease of about 3%. As noted in Section 1.5, the Reference Case includes an estimation of the expected stock growth, the likely impacts of new building, appliance and equipment standards and, finally an estimation of "natural" changes affecting energy consumption over the study period.

- In the Economic Potential scenario, natural gas savings in the total FortisBC service area are approximately 17 million GJ/yr. in 2015 and increase to approximately 22.6 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 140 million GJ/yr., a decrease of approximately 14%, relative to the Reference Case.

- In the *most likely* Achievable scenario, natural gas savings in the total FortisBC service area would be approximately 2.2 million GJ/yr. in 2015 and would increase to approximately 10.3 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 152.4 million GJ/yr., a decrease of approximately 6%, relative to the Reference Case, and a reduction in GHG emissions of approximately 516 thousand tonnes CO_2e/yr.

- In the *aggressive* Achievable Potential scenario, natural gas savings in the total FortisBC service area would be approximately 3.6 million GJ/yr. in 2015 and would increase to approximately 15.2 million GJ/yr. by 2030. The potential natural gas savings in 2030 would result in a decrease of gas consumption to approximately 147.4 million GJ/yr., a decrease of approximately 9%, relative to the Reference Case, and a reduction in GHG emissions of approximately 764 thousand tonnes CO_2e/yr.

Exhibits 4, 5 and 6 provide additional details. Exhibit 4 shows the distribution of natural gas savings by scenario, sector and milestone year, while Exhibits 5 and 6 show the resulting impacts of those savings on FortisBC's peak day capacity requirement and the reduction of greenhouse gas (GHG) emissions.

Exhibit 2 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, 3 Sectors

Milestone Year	Annual Consumption, All 3 Sectors (1000 GJ/yr.)				Potential Annual Savings, All 3 Sectors (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	167,626						
2015	159,582	142,597	157,409	155,954	16,985	2,173	3,629
2020	161,489	141,895	156,775	153,360	19,594	4,714	8,129
2025	161,995	140,350	154,611	149,958	21,644	7,383	12,037
2030	162,630	140,037	152,376	147,436	22,593	10,254	15,194

Exhibit 3 Graphic of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, 3 Sectors

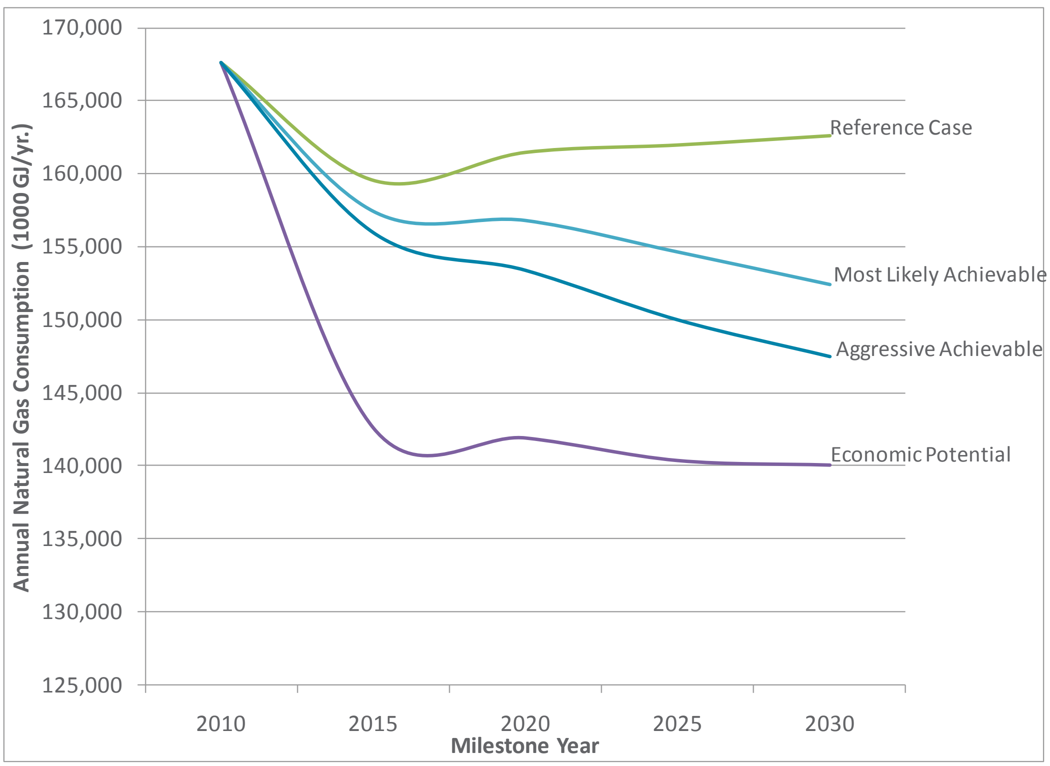


Exhibit 4 Graphic of Achievable Natural Gas Savings for the Total FortisBC Service Area by Scenario, Sector, and Milestone Year (1000 GJ/yr.), 3 Sectors

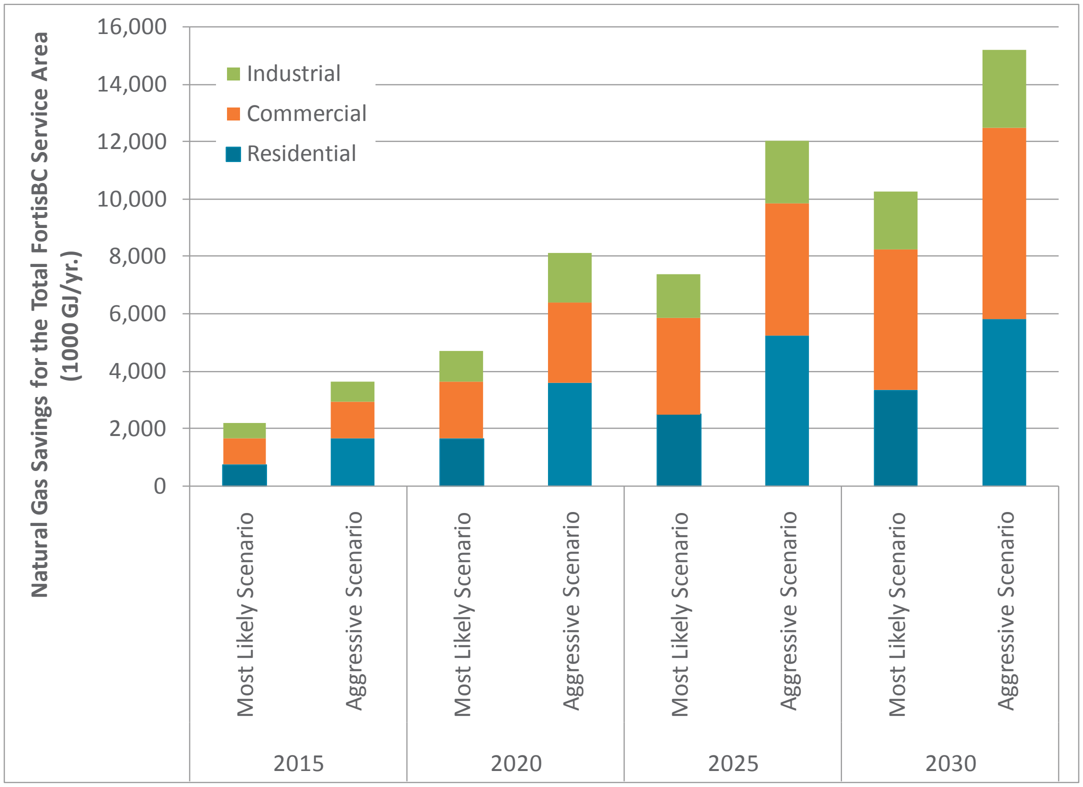


Exhibit 5 Graphic of Achievable Peak Day Capacity Impact by Scenario, Sector, and Milestone Year (GJ)

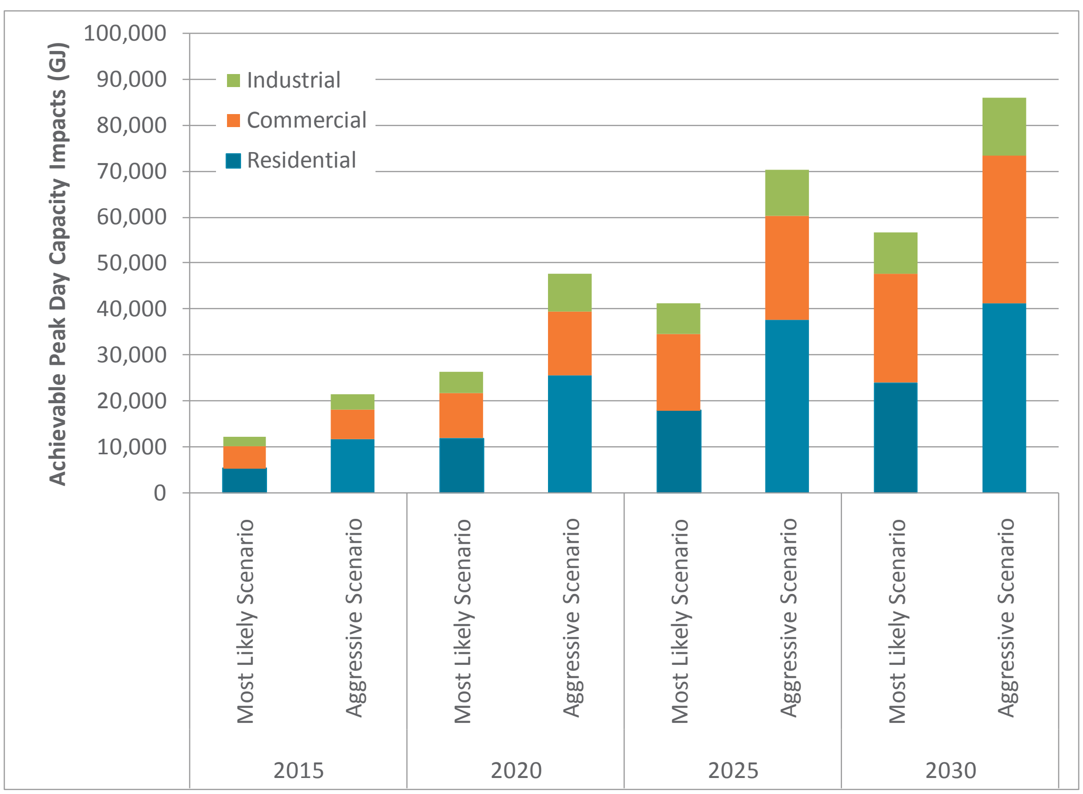
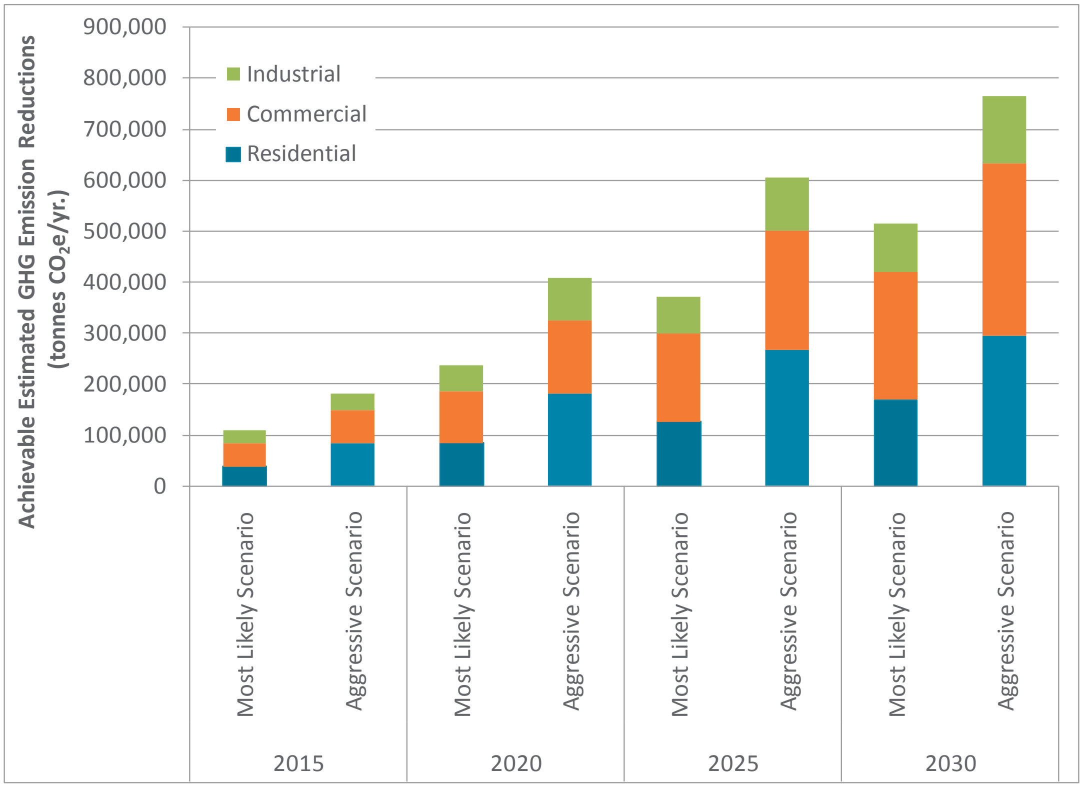


Exhibit 6 Graphic of Achievable Estimated GHG Emission Reductions by Scenario, Sector, and Milestone Year (tonnes CO_2e/yr.)



2.2 Key Observations

As was illustrated in the preceding exhibits, despite a decade of successful relatively small-scale DSM program implementation, there remains significant cost-effective DSM potential within FortisBC's service area. This remaining opportunity reflects, in part, how the continued technology cost and performance improvements have increased the availability of energy efficiency options. Key study observations are highlighted below.

Achievable Potential

Relative to the Reference Case forecast for 2030, the Achievable Potential savings range from 10.3 million GJ/yr. in the *most likely* Achievable scenario to approximately 15.2 million GJ/yr. in the *aggressive* scenario, which represent 45% and 67%, respectively, of the Economic Potential savings.

Key Technologies and Measures

In the Residential sector, space heating accounts for nearly 80% of the total energy savings. The largest contributor to these savings is the early retirement of gas furnaces, which accounts for approximately half of the total Achievable Potential savings. The remaining space heating savings are from programmable thermostats, homeowner air sealing, and improved insulation in basements, attics and walls. Fireplaces account for a further 12-13% of total energy savings; these savings are all from upgrading to more efficient fireplaces at the natural rate of replacement or new purchase.

In the Commercial sector, the most significant opportunities are actions that reduce space and water heating loads in existing buildings. Four measures account for approximately two-thirds of the savings. They are, in order of their contribution; O&M measures, advanced building automation systems, recommissioning, high-efficiency boilers, and low-flow plumbing fixtures.

In the Industrial sector, the most significant opportunities involve replacing medium size standard efficiency boilers in the food processing and manufacturing sub sectors with condensing models. For large boilers, such as in pulp mills, and for large process equipment such as cement kilns, lime kilns and coal driers, the most significant opportunities involve upgrading the equipment with better controls and heat recovery equipment. Improving the air heating efficiency of large industrial fabrication workspaces is another significant opportunity.

2.3 Additional Information

The summary of potential natural gas savings presented in this report are based on the detailed data and analysis contained in the CPR 2010 reports listed below. The reader is referred to these reports for additional information.

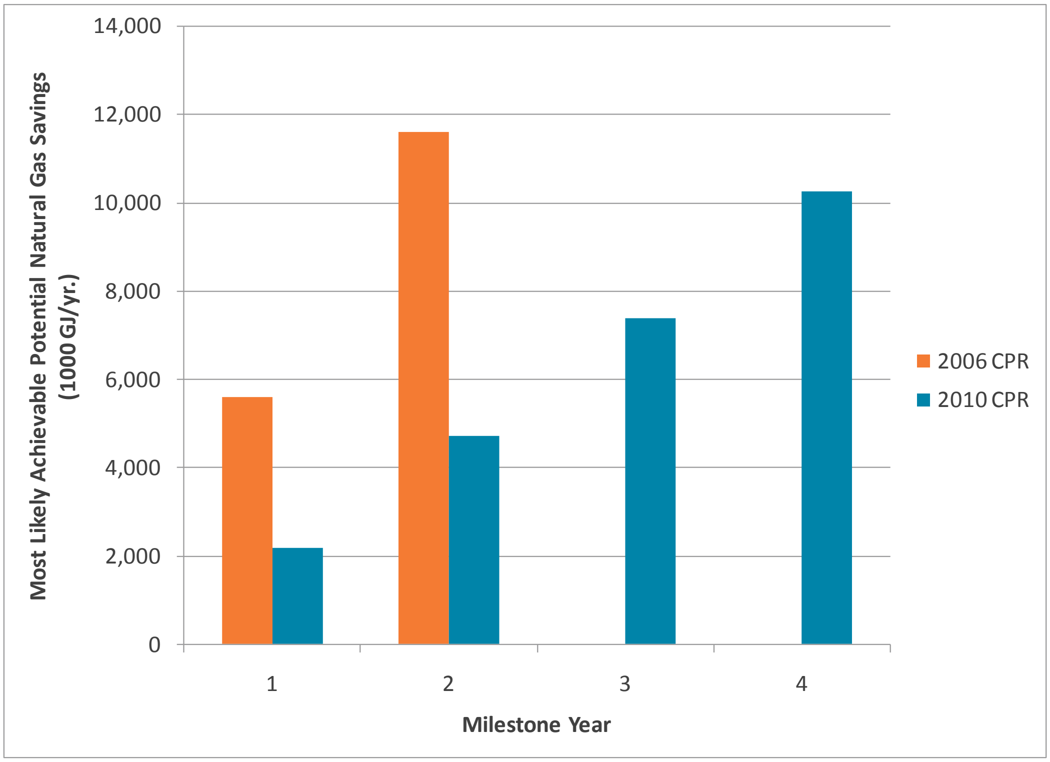
- Conservation Potential Review – 2010 FortisBC; Residential Sector Energy-efficiency, Alternative Energy and Customer Behaviour Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Commercial Sector Energy-efficiency and Alternative Energy Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Industrial Sector Energy-efficiency and Alternative Energy Opportunities (2010-2030).
- Conservation Potential Review – 2010 FortisBC; Impact of CPR 2010 Natural Gas Savings on the B.C. Economy (2010-2030).

2.3.1 Comparison of 2006 CPR Results to 2010 CPR Results

Both the 2006 and 2010 CPR results are calculated and presented at 5-year intervals, or milestone years. The milestone years in the 2006 CPR were 2011 and 2016; the milestone years in the 2010 are 2015, 2020, 2025, and 2030.

A comparison of the 2006 CPR results and the 2010 CPR results, according to milestone year is provided in Exhibit 7, overleaf.

Exhibit 7 Comparison of Annual Savings at 5-year Milestone Periods, Most Likely Achievable Potential Scenario, 2006 CPR vs 2010 CPR



The most significant contribution to the reduced level of Achievable Potential savings in the 2010 CPR relative to the 2006 CPR is the impact of energy performance standards. More specifically, the Reference Case for the 2010 CPR incorporates the expected natural gas savings from new space and water heating equipment performance standards as well as those due to new residential and commercial construction standards. These standards, which were introduced since the 2006 CPR, provide significant natural gas savings. This means that natural gas savings attributed to the new standards have been removed from the potential FortisBC program induced impacts, thus reducing the overall achievable potential.

In addition to the above market changes, there are some changes in the scope and structure of the 2010 CPR compared to the 2006 CPR:

- In contrast to the 2006 CPR, which excluded FortisBC's (then, Terasen Gas) 300 largest manufacturing accounts, the 2010 CPR includes all of FortisBC's customers, thus increasing the industrial share.

- The 2010 CPR examined only FortisBC customers whereas the 2006 CPR included all B.C. facilities, including non-FortisBC customers. The inclusion of non-FortisBC customers in the 2006 study was to facilitate a fuel choice analysis. However fuel choice was not within the scope of the 2010 CPR and, additionally, the focus on FortisBC customers (only) in the 2010 CPR enabled the study to use recent FortisBC customer market survey information.

- The approach to Commercial and Residential sector segmentation employed in the 2010 CPR differs from that employed in the 2006 CPR. The 2010 CPR includes Medium and Large Apartments in the Commercial sector; the 2006 study included them in the Residential sector. These changes were introduced to better accommodate the scope and objectives of the 2010 CPR.

- Commercial sector building profiles were also changed to incorporate more recent data. The net impact of the updates made to the 2006 CPR commercial sector building profiles for use in the 2010 CPR was an increase in “base load” (non-heating) gas consumption, especially for domestic hot water heating.

3 Residential sector

The Residential sector includes single-family detached/duplex houses, attached/row housing, and mobile/other homes. Multi-storey apartment and strata buildings are included in the Commercial sector.

3.1 Approach

The analysis of the Residential sector employed three modelling platforms:

- **HOT2000,** a commercially-supported, residential building simulation software.
- **RSEEM** (Residential Sector Energy End Use Model), a Marbek in-house spreadsheet based macro model.
- **RETScreen**, a commercially-supported, renewable energy systems modelling tool.

The major steps in the general approach to the study are outlined in Section 1.6 above (Overview of Approach). Specific procedures for the Residential sector were as follows:

- **Modelling of Base Year** – ICF Marbek used the FortisBC customer data to break down the Residential sector using four factors:

  - Type of dwelling (single detached, attached, apartment, etc.)
  - Heating category (natural gas or electric heat)
  - Building age
  - Service area.

  To estimate the natural gas used for space heating, the consultants factored in building characteristics such as insulation levels, floor space and air tightness using a variety of data sources, including the Ontario EnerGuide for Houses database, FortisBC billing data, local climate data and discussions with local contractors. They also used the results of FortisBC customer surveys that provided data on type of heating system, number and age of household appliances, renovation activity, etc. Based on the available data sources, the consultants calculated an average natural gas use by end use for each dwelling type. The consultant's models produced a close match with actual FortisBC sales data.

- **Reference Case Calculations** – For the Residential sector, the consultants developed profiles of new buildings for each type of dwelling. They estimated the growth in building stock using the same data as that contained in FortisBC's most recent load forecast and estimated the amount of natural gas used by both the existing building stock and the projected new buildings and appliances. As with the Base Year calibration, the consultant's projection closely matches FortisBC's own forecast of future natural gas requirements.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable energy savings potentials, the consultants assessed a wide range of commercially available energy-efficiency measures and technologies such as:

  - Thermal upgrades to the walls, roofs and windows of existing buildings
  - More efficient space heating equipment and controls
  - More efficient water heating equipment and measures to reduce usage
  - Improved designs for new buildings.

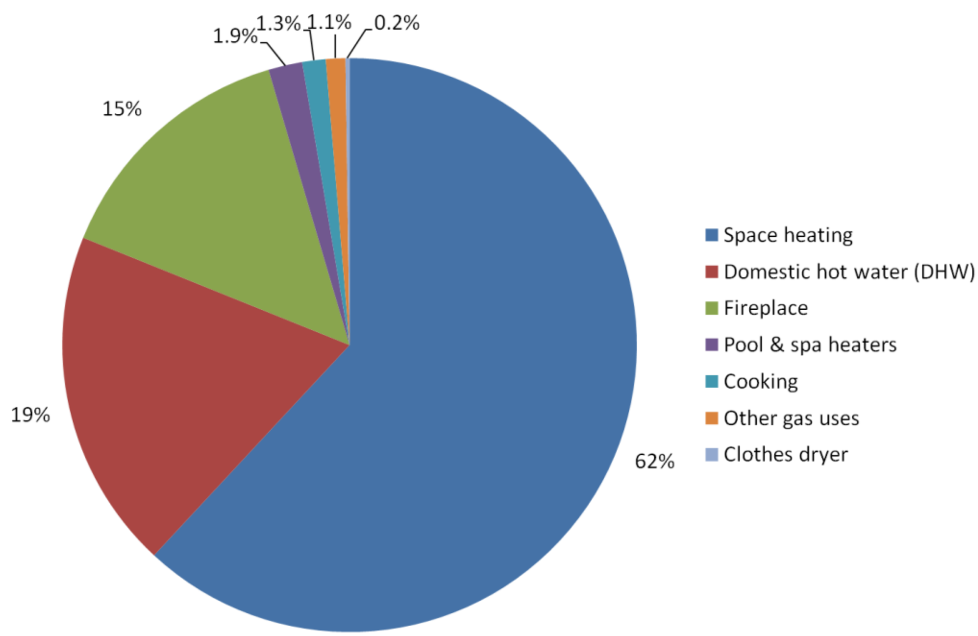
3.2 Base Year Natural Gas Use[2]

In the Base Year of 2010, FortisBC's Residential sector customers consumed approximately 74.4 million GJ of natural gas. Exhibit 8 and Exhibit 9 provide additional details on natural gas consumption by major end use and sub sector, respectively.

Exhibit 8 shows that space heating accounts for approximately 62% of the total residential natural gas use. Domestic hot water (DHW) is the next largest residential end use, accounting for approximately 19% of total residential natural gas use, followed by fireplaces (15%). Cooking, swimming pool heaters, clothes dryers, and other gas uses, combined, account for about 4% of residential natural gas use. The "Other gas uses" end use includes a variety of residential uses such as gas barbecues, outdoor fireplaces, garage or patio heaters, and outdoor lights.

Exhibit 9 shows that single-family dwellings (SFD) and duplexes account for about 92% of residential natural gas consumption followed by attached/row houses at 6%. Mobile/other dwellings account for the remaining 2% of residential natural gas use.

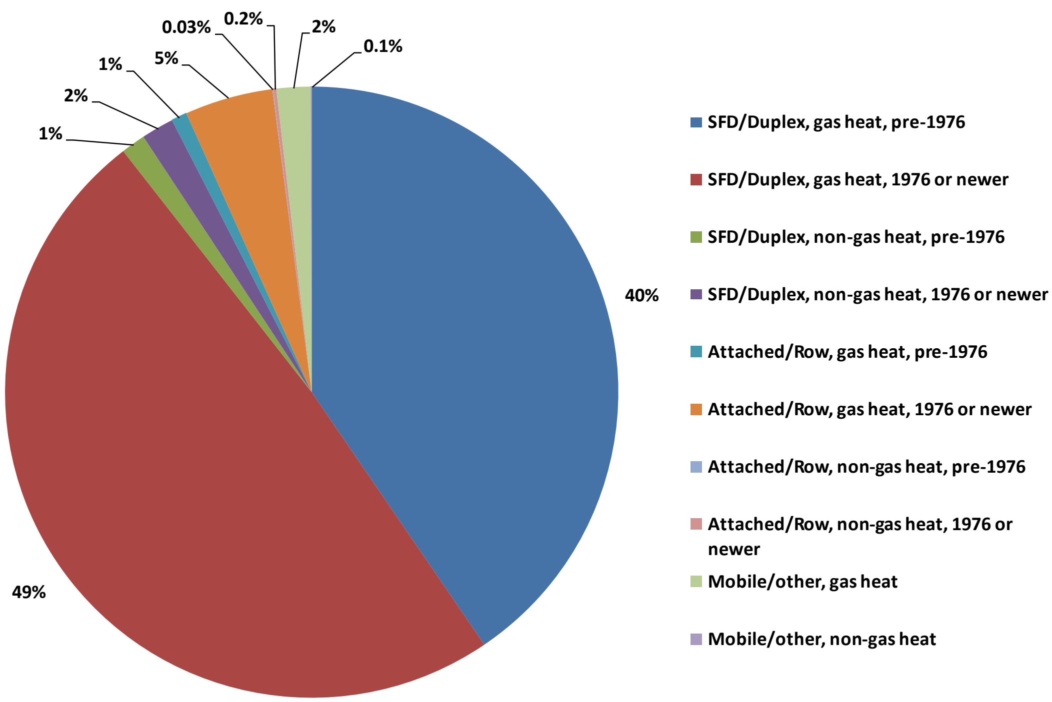
Exhibit 8 Base Year Residential Natural Gas Consumption for the Total FortisBC Service Area by End Use



[2] Readers attempting to compare these results with the CPR study completed for FortisBC (then Terasen Gas) in 2006 should be aware of two key difference between this study and the earlier one:

- The 2006 CPR was intended to complement a CPR completed for BC Hydro and therefore included all Residential sector customers of both utilities. This current study includes only those dwellings that have natural gas accounts with FortisBC.
- The 2006 CPR included high-rise multi-family buildings in the Residential sector, again for compatibility with the BC Hydro study. This study includes them in the Commercial sector, to be consistent with FortisBC's customer rate classes.

Exhibit 9 Base Year Residential Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



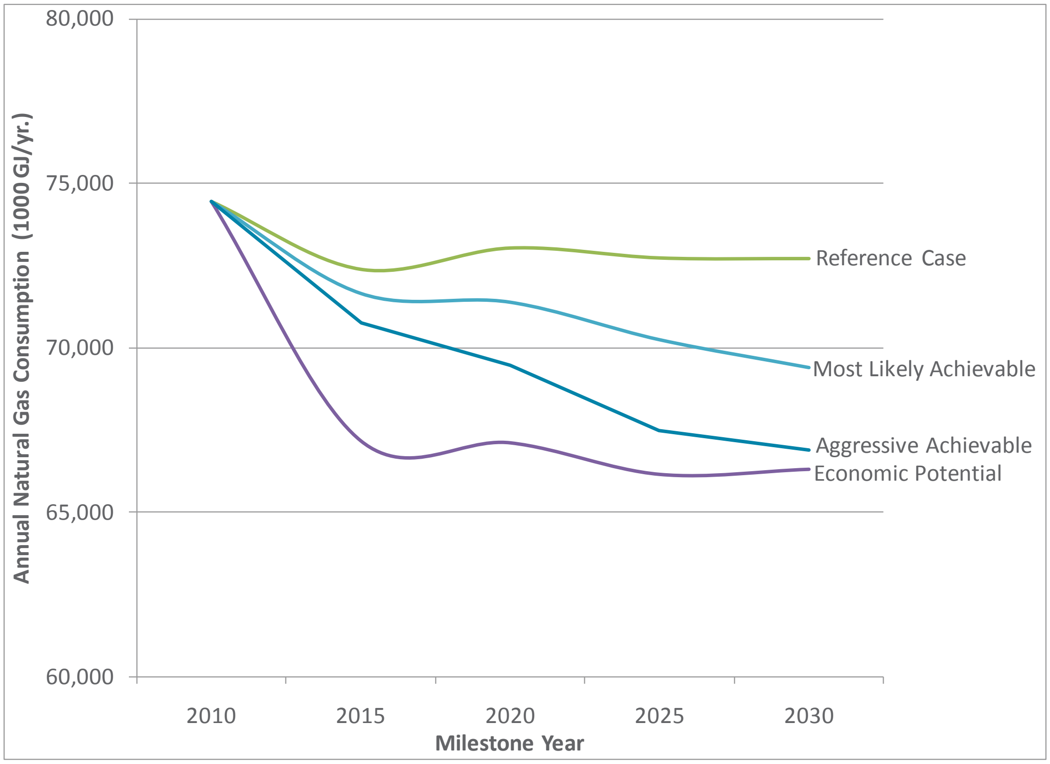
3.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 10 and Exhibit 11 and discussed briefly in the paragraphs below.

Exhibit 10 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Residential Sector

Milestone Year	Annual Consumption, Residential sector (1000 GJ/yr.)				Potential Annual Savings, Residential sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	74,440						
2015	72,382	67,173	71,638	70,742	5,209	744	1,640
2020	73,027	67,110	71,369	69,453	5,917	1,658	3,574
2025	72,726	66,152	70,226	67,474	6,574	2,500	5,252
2030	72,707	66,306	69,378	66,871	6,401	3,329	5,836

Exhibit 11 Graphic of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Residential Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Residential sector will decline from the Base Year (2010) consumption of approximately 74.4 million GJ/yr. to 73.0 million GJ/yr. by 2020 and 72.7 million GJ/yr. by 2030. This represents an overall decrease of about 2% in the period. Gas consumption per customer is expected to decline over the study period, partly because of the natural replacement of furnaces and water heaters with more efficient models, as required by new mandatory minimum efficiency standards, and partly because of new minimum performance standards for the construction of new homes. The decline in consumption per customer is expected to more than compensate for the increasing number of customers over the period, so that the overall residential gas consumption will decline.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Residential sector would decline to about 66.3 million GJ/yr. by 2030. Annual savings relative to the Reference Case are about 6.4 million GJ/yr. or about 9%. The Economic Potential annual savings are about 5.9 million GJ/yr. in 2020.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast were discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. The results are presented in Exhibit 12 and Exhibit 13 by action and by milestone year.

Exhibit 12 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (1000 GJ/yr.), Residential Sector[3]

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Domestic hot water	DHW pipe insulation	11	18	20	20	1%	17.1
Domestic hot water	Showerheads	35	49	47	38	1%	9.5
Space heating	Prog. thermostats	198	292	303	256	8%	7.1
Domestic hot water	faucet aerators	21	29	28	22	1%	5.0
Fireplace	Gas fireplaces	23	111	336	391	12%	3.5
Pool & spa heaters	Solar pool heaters	12	50	116	210	6%	1.2
Space heating	Wall insulation	8	24	46	74	2%	1.2
Domestic hot water	DHW tank insulation	2	4	5	5	0%	1.2
Space heating	Attic insulation	44	85	123	159	5%	1.2
Space heating	Basement insulation	25	71	136	217	7%	1.1
Space heating	Homeowner air sealing	60	116	169	218	7%	1.1
Domestic hot water	ESTAR clothes washers	11	29	36	26	1%	1.0
Space heating	Early retire gas furnaces	294	780	1,134	1,693	51%	0.3
Grand Total		744	1,658	2,500	3,329	100%	1.7

Exhibit 13 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (1000 GJ/yr.), Residential Sector[3]

End Use	Measure	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Domestic hot water	DHW pipe insulation	22	36	41	41	1%	17.1
Domestic hot water	Showerheads	55	78	75	60	1%	9.5
Space heating	Prog. thermostats	396	580	599	505	9%	7.0
Domestic hot water	Faucet aerators	33	46	44	35	1%	5.0
Fireplace	Gas fireplaces	46	222	667	753	13%	3.4
Pool & spa heaters	Solar pool heaters	22	90	207	377	6%	1.2
Space heating	Wall insulation	16	48	92	149	3%	1.2
Domestic hot water	DHW tank insulation	5	8	10	10	0%	1.2
Space heating	Attic insulation	88	170	247	318	5%	1.2
Space heating	Basement insulation	49	142	272	434	7%	1.1
Space heating	Homeowner air sealing	120	233	338	437	7%	1.1
Domestic hot water	ESTAR clothes washers	22	58	73	52	1%	1.0
Space heating	Early retire gas furnaces	766	1,864	2,588	2,668	46%	0.3
Grand Total		1,640	3,574	5,252	5,836	100%	1.8

[3] Early retirement of gas furnaces is included in Exhibit 12 and Exhibit 13 at the request of FortisBC. This is because, although the measure is not considered cost effective when viewed through conventional DSM screens (it does not pass the TRC test as applied in this study), fully 76% of FortisBC's customers (or 91% of those who heat with gas furnaces) have standard- and mid-efficiency furnaces. It is the desire of FortisBC to offer its customers a program to encourage these customers to replace their standard- and mid-efficiency furnaces at or before the end of equipment life with high-efficiency furnaces. Thus, FortisBC wanted to discover through this study the impacts of such a program on the savings available from the Residential sector.

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 14 and Exhibit 15. As illustrated, the Achievable peak day savings in 2030 range from a decrease of about 34,000 GJ/day (*most likely* scenario) to a decrease of approximately 59,000 GJ/day (*aggressive* scenario) for the total FortisBC service region.

Exhibit 14 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	5,294	1,224	747	256	17	7,539
2020	11,830	2,670	1,695	575	29	16,800
2025	17,913	3,840	2,543	995	28	25,319
2030	23,904	5,182	3,398	1,215	25	33,724
Savings 2030 Relative to Total 2030 Savings	71%	15%	10%	4%	0.1%	100%

Exhibit 15 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	11,686	2,683	1,676	530	39	16,614
2020	25,557	5,711	3,705	1,181	60	36,214
2025	37,702	8,034	5,410	1,997	54	53,196
2030	41,351	9,632	5,890	2,205	47	59,126
Savings 2030 Relative to Total 2030 Savings	70%	16%	10%	4%	0.1%	100%

Electricity Impacts

The natural gas savings associated with the Economic Potential scenario shown in Exhibit 10 would also result in collateral electricity savings as some efficiency measures affect both energy sources. The study estimated that in 2030 the natural gas efficiency measures contained in the Economic Potential scenario would result in additional electrical savings of 24 GWh/yr.

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable energy-efficiency scenarios shown in Exhibit 12 and Exhibit 13 would result in significant greenhouse gas reductions. The study estimated that in 2030 the natural gas efficiency measures contained in the *aggressive* and *most likely* Achievable Potential scenarios would reduce GHG emissions by 296,000 and 169,000 of CO_2e/yr., respectively. Further details are provided in Exhibit 16 and Exhibit 17. The electricity savings associated with the natural gas efficiency measures would also result in additional GHG reductions, which have not been included in this calculation.

Exhibit 16 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	26,603	6,032	3,681	1,322	85	37,724
2020	59,447	13,156	8,352	2,966	146	84,067
2025	90,014	18,917	12,530	5,139	138	126,737
2030	120,118	25,530	16,741	6,270	126	168,785
Savings 2030 Relative to Total 2030 Savings	71%	15%	10%	4%	0.1%	100%

Exhibit 17 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Residential Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	58,723	13,220	8,255	2,738	192	83,129
2020	128,426	28,136	18,252	6,096	301	181,211
2025	189,455	39,580	26,653	10,307	268	266,263
2030	207,792	47,455	29,016	11,384	236	295,883
Savings 2030 Relative to Total 2030 Savings	70%	16%	10%	4%	0.1%	100%

Achievable Potential - Customer Behaviour

The study also assessed potential from customer behaviours changes. Exhibit 18 presents a summary of the results for both the *aggressive* and *most likely* achievable potential scenarios.

It should be noted that there is significant potential overlap with the reported savings from energy efficiency technologies. Consequently, the behaviour savings shown in Exhibit 18 have not been added to those for the energy efficiency technologies.

Exhibit 18 Achievable Potential from Customer Behaviour Changes, Aggressive and Most Likely Achievable Natural Gas Savings, by Milestone Year (1000 GJ/yr.)

Achievable Scenario	Energy Impact (1000 GJ/yr.)			
	2015	2020	2025	2030
Most Likely	383	975	1,727	2,649
Aggressive	199	518	930	1,439

3.4 Summary of Findings

The study findings confirm the existence of potential cost-effective natural gas efficiency improvements in British Columbia's Residential sector, but highlight the increasing challenges in finding opportunities. In the *most likely* and *aggressive* Achievable scenarios energy-efficiency improvements would provide between 3,329,000 and 5,836,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 34,000 to 59,000 GJ.

These potential savings are smaller than those found in previous studies, both because of the success of previous program initiatives on the part of FortisBC and other utilities, and because of new standards for furnaces, water heaters, and new home construction. Consequently, there is a need to look beyond the "easy" and the "conventional" to more innovative approaches to seeking continued energy-efficiency and GHG reduction opportunities.

As an example of one possible approach, this study explored the potential offered by early retirement of gas furnaces. This measure was included in the Achievable Potential at the request of FortisBC. This is because although the measure is not considered cost effective when viewed through conventional DSM screens (it does not pass the measure TRC test as applied in this study), fully 76% of FortisBC's customers (or 91% of those who heat with gas furnaces) have standard and mid-efficiency furnaces. It is the desire of FortisBC to offer its customers a program to encourage these customers to replace their standard and mid-efficiency furnaces before the end of equipment life with high-efficiency furnaces.

Partly because of the inclusion of the furnace early retirement measure, space heating accounts for nearly 80% of the total energy savings in the two Achievable Potential scenarios. The largest contributor to these savings is the early retirement of gas furnaces, which accounts for approximately half of the total Achievable Potential savings. Improvements in gas fireplace efficiency offer 12-13% of the total energy savings in the two Achievable Potential scenarios, swimming pool heater efficiency offers 6%, and water heating efficiency offers 3% of the savings.

4 Commercial Sector

The Commercial sector includes office and retail buildings, hotels and motels, restaurants, high-rise and mid-rise apartments, warehouses and a variety of small buildings. In this study, it also includes buildings that are often classified as "institutional," such as hospitals and nursing homes, schools and universities.

Throughout this report, use of the word "commercial" includes both commercial and institutional buildings, unless otherwise noted.

4.1 Approach

The detailed end-use analysis of energy-efficiency opportunities in the Commercial sector employed two linked modelling platforms: **CEEAM** (Commercial Energy and Emissions Analysis Model), an ICF Marbek in-house simulation model developed in conjunction with Natural Resources Canada (NRCan) for modelling natural gas use in commercial/institutional building stock, and **CSEEM** (Commercial sector Energy End-use Model), an in-house spreadsheet-based macro model.

The major steps in the general approach to the study were outlined in Section 1.6. Specific procedures for the Commercial sector were as follows:

- **Modelling of Base Year** – ICF Marbek compiled data that defines "where" and "how" natural gas is currently used in existing commercial buildings. The consultants then created building energy-use simulations for each type of commercial building and calibrated the models to reflect actual FortisBC customer sales data. Estimated savings for the Other Commercial Buildings category were derived from the results of the modelled segments. They did not directly model that category because it is extremely diverse and the natural gas use of individual facility types is relatively small. The consultant's model produced a close match with actual FortisBC sales data.

- **Reference Case Calculations** – For the Commercial sector, ICF Marbek developed detailed profiles of new buildings in each of the building segments, estimated the growth in building stock and estimated "natural" changes affecting natural gas consumption over the study period. As with the Base Year calibration, the consultant's projection closely matches the FortisBC 2010 forecast of future natural gas requirements.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:

  - Measures to improve building envelope efficiency
  - Measures to reduce domestic hot water use, including solar hot water systems
  - Upgraded heating and ventilating systems
  - Improved construction in new buildings
  - Efficient cooking appliances.

4.2 Base Year Natural Gas Use

In the Base Year of 2010, FortisBC's Commercial sector customers consumed approximately 57 million GJ. Exhibit 19 and Exhibit 20 provide additional details on natural gas consumption by major end use and sub sector, respectively.

Exhibit 19 shows that space heating accounts for approximately 59% of the total Commercial sector natural gas use. Domestic hot water heating is the next largest end use, accounting for approximately 25% of total commercial natural gas use, followed by commercial cooking (15%). Other end uses such as dehumidification, steam system distribution losses, laundry equipment, and pool heating account for about 7% of commercial natural gas use.

Exhibit 20 shows that Small Commercial buildings account for about 30% of natural gas consumption followed by Large and Medium Apartments, (approximately 25% combined). No other sub sector accounts for more than 10% of Commercial sector natural gas use.

Exhibit 19 Base Year Commercial Natural Gas Consumption for the Total FortisBC Service Area by End Use

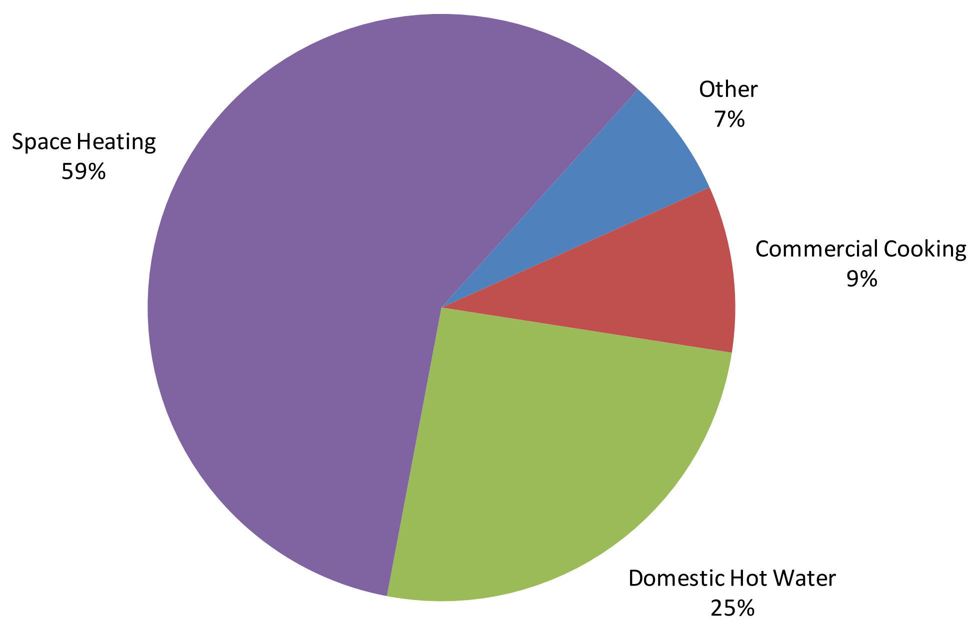
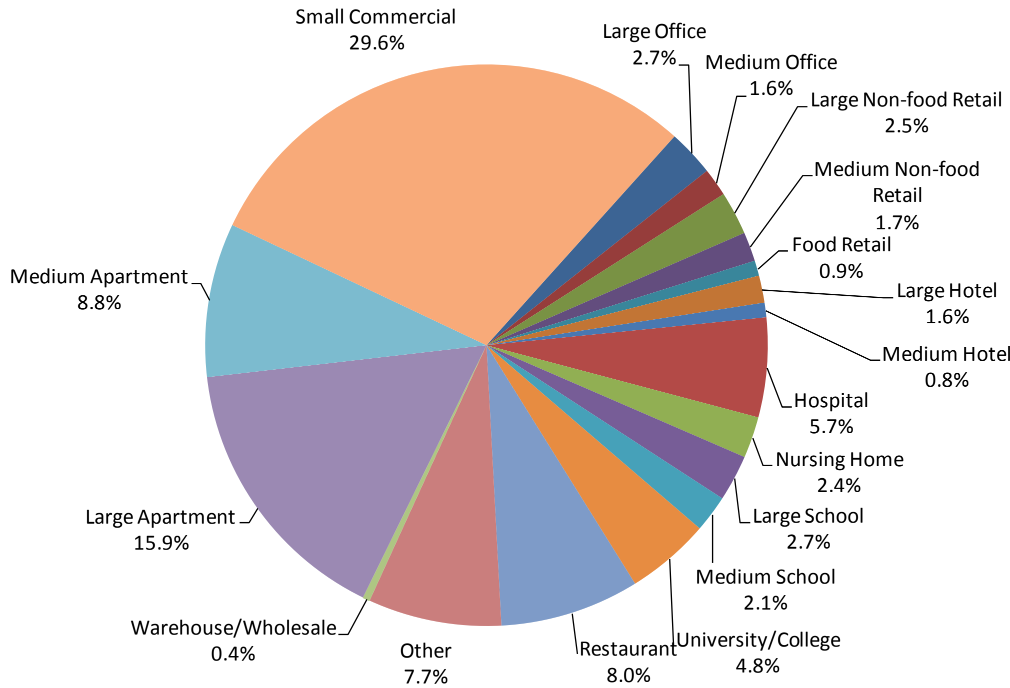


Exhibit 20 Base Year Commercial Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



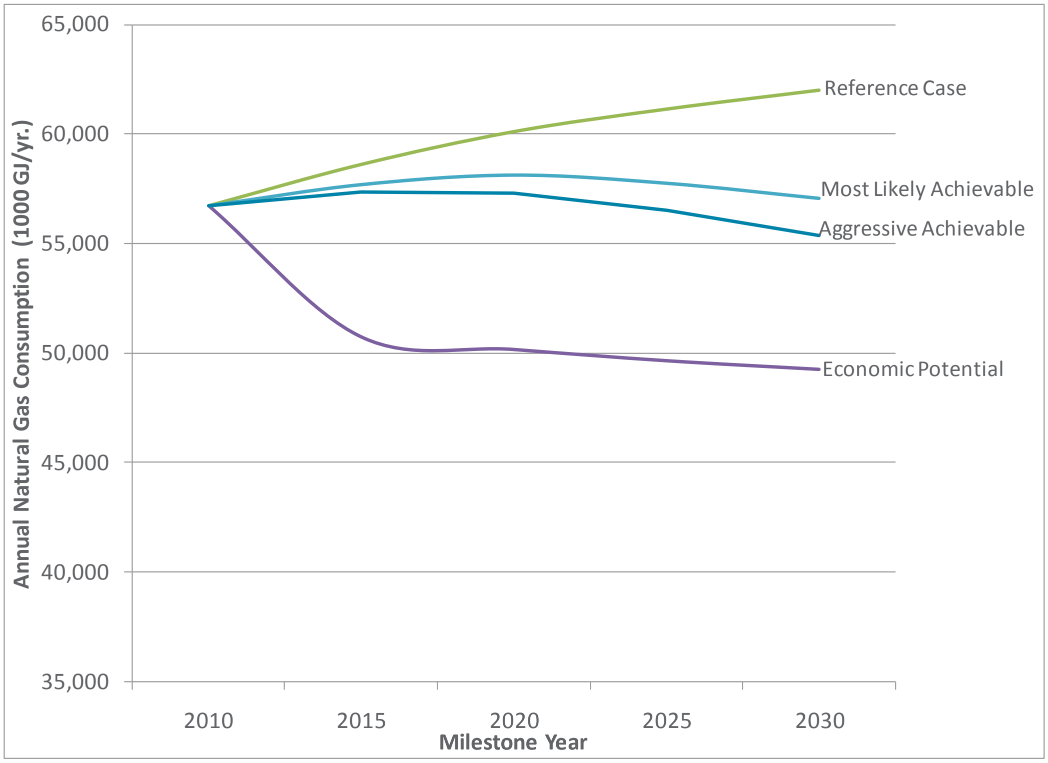
4.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 21 and Exhibit 22 and discussed briefly in the paragraphs below.

Exhibit 21 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Commercial Sector

Milestone Year	Annual Consumption, Commercial sector (1000 GJ/yr.)				Potential Annual Savings, Commercial sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	56,730						
2015	58,607	50,714	57,676	57,332	7,893	930	1,275
2020	60,095	50,137	58,104	57,286	9,958	1,991	2,809
2025	61,118	49,622	57,739	56,498	11,496	3,379	4,619
2030	61,977	49,225	57,062	55,344	12,752	4,915	6,633

Exhibit 22 Graphic of Forecast Results for the Total FortisBC Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Commercial Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Commercial sector will increase from the Base Year (2010) consumption of approximately 56.7 million GJ/yr. to 60.1 million GJ/yr. by 2020 and 62.0 million GJ/yr. by 2030. This represents an overall increase of about 9% in the period.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Commercial sector would decline to about 49.2 million GJ/yr. by 2030. Annual savings relative to the Reference Case are about 12.8 million GJ/yr. or about 22%. The Economic Potential annual savings are about 10 million GJ/yr. in 2020.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast was discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. Results by sub sector and end use are presented in Exhibit 23 and Exhibit 24 for both Achievable scenarios.

Exhibit 23 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by Measure and Milestone Year (GJ/yr.), Commercial Sector

End Use	Measure	2015	2020	2025	2030	% Savings Relative to Total 2030 Savings	Average B/C Ratio
Domestic Hot Water	Pre-Rinse Spray Valves	57,607	84,693	110,297	107,352	2.2%	16.70
Domestic Hot Water	Ultra Low-Flow Fixtures	195,943	288,323	376,043	366,771	7.5%	8.61
Space Heating	Demand Ctrl Kitchen Vent.	4,091	7,913	11,414	14,537	0.3%	5.27
Domestic Hot Water	Condensing DHW (Boiler)	1,665	12,285	39,274	89,919	1.8%	3.08
Multiple	New Construction 40% Better	1,429	10,292	31,621	70,396	1.4%	3.07
Space Heating	Programmable T'stats	54,957	107,153	155,816	200,101	4.1%	2.77
Domestic Hot Water	Condensing DHW (Tank Type)	1,815	13,390	42,773	73,296	1.5%	2.58
Multiple	BAS and Recommissioning	162,255	316,967	461,728	593,864	12.1%	2.49
Space Heating	Air Sealing	895	3,522	7,737	13,290	0.3%	1.86
Space Heating	Condensing Rooftop Units	847	3,268	7,025	11,780	0.2%	1.83
Space Heating	Condensing Boilers	35,149	135,083	290,443	490,417	10.0%	1.70
Commercial Cooking	HE Cooking	3,188	24,210	54,931	98,972	2.0%	1.62
Space Heating	Air-Air Heat Recovery	54,621	105,301	151,557	192,958	3.9%	1.52
Multiple	O&M Measures	50,292	197,566	436,475	761,752	15.5%	1.38
Space Heating	Roof Insulation	1,981	14,928	48,739	112,200	2.3%	1.26
Space Heating	Condensing Unit Heater	60	232	496	832	0.0%	1.21
Domestic Hot Water	Drainwater Heat Recovery	335	1,234	2,614	4,439	0.1%	1.19
Space Heating	HVLS Fans	687	1,322	1,896	2,394	0.0%	1.19
Space Heating	Demand Ctrl Vent.	953	1,831	2,610	3,264	0.1%	1.17
Space Heating	Infrared Heaters	0	1,360	2,589	3,666	0.1%	1.16
Multiple	Small Commercial	241,293	527,453	911,955	1,357,598	27.6%	-
Multiple	Other	60,181	132,367	230,676	345,306	7.0%	-
Grand Total		930,246	1,990,692	3,378,709	4,915,107	100%	3.20

Exhibit 24 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Measure and Milestone Year (GJ/yr.), Commercial Sector

End Use	Measure	2015	2020	2025	2030	% Savings Relative to Total 2030 Savings	Average B/C Ratio
Domestic Hot Water	Pre-Rinse Spray Valves	41,645	81,398	119,287	155,341	2.3%	16.7
Domestic Hot Water	Ultra Low-Flow Fixtures	141,808	277,565	407,352	531,248	8.0%	8.61
Space Heating	Demand Ctrl Kitchen Vent.	5,599	10,760	15,463	19,670	0.3%	5.27
Domestic Hot Water	Condensing DHW (Boiler)	3,129	22,869	72,630	163,162	2.5%	3.08
Multiple	New Construction 40% Better	9,819	37,046	77,103	129,782	2.0%	3.07
Space Heating	Programmable T'stats	68,187	132,389	192,234	243,154	3.7%	2.77
Domestic Hot Water	Condensing DHW (Tank Type)	3,418	24,969	79,015	131,989	2.0%	2.58
Multiple	BAS and Recommissioning	201,268	391,471	569,360	699,843	10.6%	2.49
Space Heating	Air Sealing	4,262	8,345	12,163	15,573	0.2%	1.86
Space Heating	Condensing Rooftop Units	1,155	4,405	9,364	15,529	0.2%	1.83
Space Heating	Condensing Boilers	48,013	182,990	391,328	660,997	10.0%	1.7
Commercial Cooking	HE Cooking	4,959	37,659	85,447	153,957	2.3%	1.62
Space Heating	Air-Air Heat Recovery	74,708	143,060	205,251	262,327	4.0%	1.52
Multiple	O&M Measures	241,403	474,158	698,360	914,103	13.8%	1.38
Space Heating	Roof Insulation	3,442	25,847	84,415	195,136	2.9%	1.26
Space Heating	Condensing Unit Htr.	82	313	665	1,109	0.0%	1.21
Domestic Hot Water	Drainwater Heat Recovery	630	2,292	4,797	7,910	0.1%	1.19
Space Heating	HVLS Fans	939	1,793	2,554	3,207	0.0%	1.19
Space Heating	Demand Ctrl Vent.	1,298	2,464	3,469	4,295	0.1%	1.17
Space Heating	Infrared Heaters	0	1,838	3,474	4,884	0.1%	1.16
Multiple	Small Commercial	334,939	753,649	1,263,001	1,846,194	27.8%	-
Multiple	Other	84,288	191,639	322,624	473,670	7.1%	-
Grand Total		1,274,993	2,808,920	4,619,354	6,633,079	100%	3.32

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 25 and Exhibit 26. As illustrated, the Achievable peak day savings in 2030 range from a decrease of about 38,000 GJ in the *most likely* Achievable scenario to a decrease of approximately 51,000 GJ in the *aggressive* Scenario for the total FortisBC service region.

Exhibit 25 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	4,714	744	802	849	31	7,141
2020	9,904	1,675	1,753	1,883	66	15,281
2025	16,637	2,977	3,012	3,197	113	25,936
2030	23,786	4,537	4,502	4,740	164	37,729
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	13%	0.4%	100%

Exhibit 26 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	6,424	1,058	1,061	1,202	42	9,787
2020	13,983	2,461	2,401	2,623	94	21,562
2025	22,688	4,212	4,092	4,314	154	35,459
2030	32,115	6,298	6,100	6,182	221	50,917
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	12%	0.4%	100%

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable energy-efficiency scenarios shown in Exhibit 27 and Exhibit 28 would result in significant GHG reductions. The study estimated that in 2030 the natural gas efficiency measures contained in the *aggressive* and *most likely* Achievable Potential scenarios would reduce GHG emissions by 338,000 and 250,000 of CO_2e/yr., respectively.

Exhibit 27 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	31,274	4,933	5,321	5,635	206	47,369
2020	65,701	11,108	11,626	12,493	440	101,368
2025	110,366	19,747	19,978	21,209	747	172,047
2030	157,787	30,100	29,865	31,444	1,087	250,283
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	13%	0.4%	100%

Exhibit 28 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Commercial Sector

Year	Lower Mainland	Vancouver Island	Southern Interior	Northern Interior	Whistler	Grand Total
2015	42,613	7,020	7,035	7,974	282	64,924
2020	92,758	16,325	15,927	17,402	620	143,033
2025	150,501	27,939	27,145	28,617	1,021	235,222
2030	213,041	41,776	40,468	41,012	1,468	337,765
Savings 2030 Relative to Total 2030 Savings	63%	12%	12%	12%	0.4%	100%

4.4 Summary of Findings

The study findings confirm the existence of significant potential cost-effective natural gas efficiency improvements in British Columbia's Commercial sector. In the *most likely* and *aggressive* Achievable scenarios those energy-efficiency improvements would provide between 4,915,000 and 6,633,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 38,000 to 51,000 GJ. Savings are primarily associated with the space heating and water heating end uses, with approximately two-thirds of the savings in both Achievable scenarios associated with space heating measures.

Four measures each account for more than 10% of the savings in both the *most likely* and *aggressive* Achievable scenarios. These are, in order of their contribution: O&M measures, advanced building automation systems/recommissioning, high-efficiency boilers, and low-flow plumbing fixtures. These four measures represent a total of 69% of the *most likely* Achievable scenario savings and 65% of the *aggressive* Achievable scenario savings.

5 Industrial Sector

The Industrial sector consists of the eight largest natural gas consuming Industrial sub sectors within the FortisBC service area, an additional category (Other) that combines the remaining smaller industry groups, and the agriculture sub sector. The largest natural gas consuming Industrial sub sectors within the FortisBC service area, which are the primary focus of this study, are: Chemical, Fabricated Metal, Food & Beverage, Mining, Miscellaneous Manufacturing, Non-Metal Manufacturing, Pulp & Paper, and Wood Products.

This study includes analysis of the interruptible natural gas loads for large customers and the savings measures associated with their process requirements. As a result the Mining and Pulp and Paper sub sectors have been added for the 2010 review, compared to those sub sectors previously studied in the 2006 CPR.

5.1 Approach

The analysis of the Industrial sector employed a customized spreadsheet model. The model applies appropriate end-use technologies to each sub sector in each service area. The input energy-use information and equipment efficiencies are organized by service area, major sub sector, major end use, and technology.

The major steps in the general approach to the study were outlined in Section 1.6. Specific procedures for the Industrial sector were as follows:

- **Modelling of Base Year** – The consultants compiled data that defines "where" and "how" natural gas is currently used in industry. The primary input variables affecting the consumption of natural gas, based on industrial process, are:
  - Type and efficiency of specific major processing equipment
  - Energy consumption and operating hours for heating equipment
  - Economic activity levels within each sub sector (useful heat requirement)
  - Production processes employed.

- The average natural gas consumption for June through August provided the basis for the annual process heat load for the industries, with process consumption not affected by climate.

- **Reference Case Calculations** – The energy-use changes that would occur without utility programs are in the Reference Case. A constant rate of improvement was applied for each technology that reflects the natural rate of equipment replacement and upgrades seen in B.C.'s Industrial sector. The natural gas sales were calculated for each sub sector and service area along with the useful heat based on the conversion efficiencies of technologies for both comfort and process heating.

- **Assessment of DSM Measures** – To estimate the Economic and Achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:
  - Controls and high-efficiency burners (bundled standard upgrades)
  - Heat recovery (off of boiler)
  - Insulation – equipment and distribution systems
  - Heat recovery (off of process)
  - Optimized heat balance and control
  - Steam trap maintenance.

5.2 Base Year Natural Gas Use

In the Base Year of 2010, FortisBC's Industrial sector customers consumed approximately 36,456,000 GJ. Exhibit 29 and Exhibit 30 provide additional details of the Industrial sector natural gas consumption by major end uses and sub sector, respectively.

Exhibit 29 shows that boilers account for approximately 43% of the total industrial natural gas use. Most of the boiler load involves process steam use. Furnaces for air heating large industrial areas account for about 12% of the industrial consumption and another 12% is used in kilns at pulp and paper sites, and for manufacturing lime for the Kraft pulping process. The remaining natural gas is used in a variety of industrial processes, including lumber kilns, coal driers, and cement kilns.

Exhibit 30 indicates the distribution among the sub sectors. The Pulp and Paper sector dominates at 32%, followed by Agriculture, Food & Beverage at 12% each, Chemical at 10%, Wood Products at 9%, Mining at 8%, and Fabricated Metal at 6%.

Exhibit 29 Base Year Industrial Natural Gas Consumption for the Total FortisBC Service Area by End Use

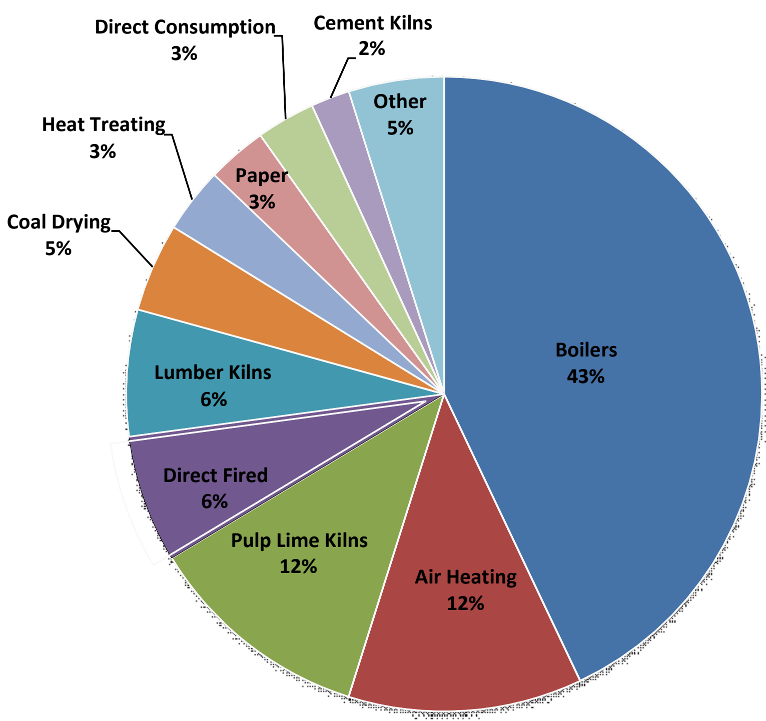
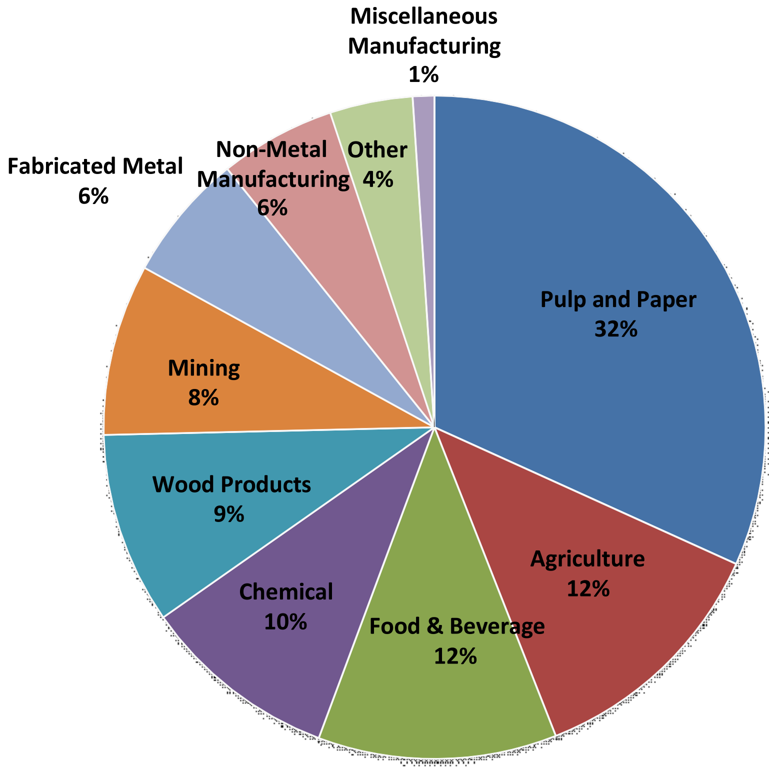


Exhibit 30 Base Year Industrial Natural Gas Consumption for the Total FortisBC Service Area by Sub Sector



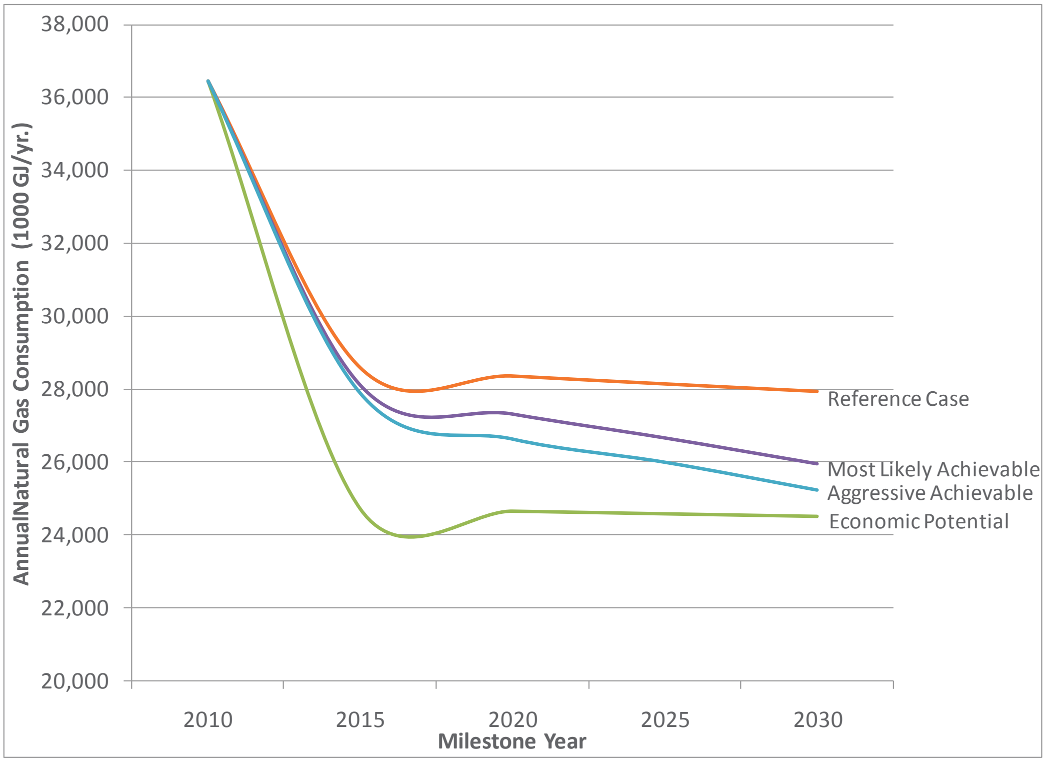
5.3 Results and Findings

A summary of the levels of annual natural gas consumption contained in the Reference Case and each of the energy-efficiency forecasts by milestone year is presented in Exhibit 31 and Exhibit 32 and discussed briefly in the paragraphs below.

Exhibit 31 Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector

Milestone Year	Annual Consumption, Industrial sector (1000 GJ/yr.)				Potential Annual Savings, Industrial sector (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Most Likely	Aggressive		Most Likely	Aggressive
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2010	36,456						
2015	28,594	24,710	28,095	27,880	3,884	499	714
2020	28,367	24,648	27,302	26,621	3,719	1,065	1,746
2025	28,151	24,576	26,646	25,985	3,575	1,505	2,166
2030	27,946	24,506	25,936	25,221	3,440	2,010	2,725

Exhibit 32 Graphic of Forecast Results for the Total FortisBC Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector



Reference Case

In the absence of continued DSM initiatives, the study estimates that natural gas consumption in the Industrial sector will decline from the base year (2010) consumption of approximately 36.5 million GJ/yr. to 28.4 million GJ/yr. by 2020 and 27.9 million GJ/yr. by 2030. This represents an overall decrease of about 23% in the period. The forecast decrease is due to an expected continued decline in the wood products and pulp and paper industry as well as a continuation of the move to wood waste from natural gas. The move to wood waste will be mainly due to the provincial government policy of encouraging a reduction of GHG emissions.

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast, the study estimated that consumption in the Industrial sector would decline to about 24,506,000 GJ/yr. by 2030. Annual savings relative to the Reference Case are about 3,439,000 GJ/yr. or about 12%. The Economic Potential is obtained relatively quickly due to the analysis indicating that, from a strictly economic perspective, most of the inefficient equipment could be replaced by more efficient alternatives within the next five years.

Achievable Potential – Energy-efficiency Scenario

A selection of the natural gas savings opportunities identified in the Economic Potential Forecast were discussed in a full-day workshop. The guided participant discussions provided estimated levels of participation under a *most likely* scenario of program activity and an *aggressive* scenario of program activity. These levels were applied to the Economic Potential savings to estimate the Achievable Potential for these two scenarios. For technologies not specifically discussed in the workshops, participation levels were estimated through extrapolation from the technologies that were discussed. The results are presented in Exhibit 33 and Exhibit 34 by technology and by milestone year for the *most likely* and *aggressive* Achievable Potential scenarios, respectively.

Exhibit 33 Most Likely Achievable Natural Gas Savings for the Total FortisBC Service Area by End Use and Milestone Year (GJ/yr.), Industrial Sector

End Use	2015	2020	2025	2030	% Savings 2030 Relative to Ref Case	% Savings 2030 Relative to Total 2030 Savings
Boilers	256,269	527,267	823,065	1,153,094	9%	57%
Air heating	88,567	174,994	259,343	341,709	11%	17%
Ovens	470	4,134	6,278	8,748	1%	0.4%
Heat treating	1,809	16,439	23,073	29,753	6%	1%
Lumber kilns	48,534	97,260	140,724	180,165	29%	9%
Veneer dryers	6,116	12,044	17,723	23,097	1%	1%
Pulp lime kilns	2,884	8,117	15,777	25,538	6%	1%
Cement kilns	6,395	13,015	17,758	21,494	3%	1%
Ore drying	1,016	2,435	2,639	2,964	0%	0.1%
Coal drying	53,356	127,832	110,862	124,497	24%	6%
Direct fired	34,172	81,391	88,010	98,828	6%	5%
Grand Total	499,589	1,064,929	1,505,251	2,009,988	7%	100%

Exhibit 34 Aggressive Achievable Natural Gas Savings for the Total FortisBC Service Area by Technology and Milestone Year (GJ/yr.), Industrial Sector

End Use	Sub Sector	2015	2020	2025	2030	% Savings 2030 Relative to Total 2030 Savings	Average B/C Ratio
Coal drying	High-efficiency coal and ore dryers	55,388	132,701	116,140	130,425	5%	15 (coal)
Ore drying	High-efficiency kilns	2,558	23,427	33,149	42,988	2%	9.1
Cement kilns	High-efficiency kilns	7,211	20,293	39,441	63,846	2%	7
Direct fired	Direct-fired heating - gypsum	68,344	162,783	176,021	197,856	7%	5.5
Ovens	High-efficiency ovens	940	8,268	12,555	17,497	1%	5.4
Heat treating	Heat treating furnace with sequential firing, high-velocity burners	3,619	32,879	46,145	59,507	2%	5.4
Veneer dryers	Advanced veneer dryer	9,785	19,271	28,357	36,955	1%	5.4
Air heating	Radiant tube heating	110,709	218,743	324,178	427,137	16%	4.4
Lumber kilns	High-efficiency kilns	64,712	129,680	187,632	240,220	9%	4.2
Boilers	Efficient boilers	373,963	950,508	110,661	1,367,177	50%	~4
Process water heating	Direct-fired water heating	7,988	24,561	50,261	81,010	3%	N/A
Pulp lime kilns	Direct-fired paper drying	8,871	23,500	41,621	60,576	2%	N/A
Grand Total		714,089	176,613	2,166,162	2,725,193	100%	

Peak Day Load Impacts – Energy-efficiency Scenarios

The peak day savings associated with each of the Achievable energy-efficiency scenarios were calculated using load factor data provided by FortisBC. The results are summarized in Exhibit 35 and Exhibit 36. As illustrated, the Achievable peak day savings in 2030 range from a decrease of 16,990 GJ in the *most likely* Achievable scenario to a decrease of 23,080 GJ/day in the *aggressive* scenario for the total FortisBC service region.

Exhibit 35 Most Likely Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	2,197	936	971	110	4,213
2020	4,633	1,936	2,150	227	8,973
2025	6,749	2,978	2,659	328	12,715
2030	9,055	4,064	3,462	409	16,990
Savings 2030 Relative to Total 2030 Savings	53%	24%	20%	2%	100%

Exhibit 36 Aggressive Achievable Peak Day Capacity Impacts by Service Region and Milestone Year (GJ), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	3,250	1,398	1,228	162	6,093
2020	8,064	3,367	2,990	373	14,794
2025	10,003	4,424	3,442	476	18,346
2030	12,544	5,694	4,285	556	23,080
Savings 2030 Relative to Total 2030 Savings	54%	25%	19%	2%	100%

Greenhouse Gas Impacts – Energy-efficiency Scenarios

The natural gas savings associated with each of the Achievable Potential scenarios would also result in a reduction of GHG emissions.[4] As illustrated in Exhibit 37 and Exhibit 38, by 2030 the GHG reductions are estimated to be in the range of 96,000 to 130,000 tonnes CO_2e per year, depending on the scenario.

[4] GHG impacts are estimated based on an emissions factor of 48kg of CO_2e/GJ of natural gas. This is the B.C. Natural Gas Emission Factor.

Exhibit 37 Most Likely Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	11,361	5,809	6,027	783	23,980
2020	23,960	12,187	13,352	1,617	51,117
2025	34,906	18,493	16,509	2,343	72,252
2030	46,833	25,233	21,494	2,920	96,479
Savings 2030 Relative to Total 2030 Savings	49%	26%	22%	3%	100%

Exhibit 38 Aggressive Achievable Estimated GHG Emission Reductions by Scenario and Milestone Year (tonnes CO_2e/yr.), Industrial Sector

Year	Lower Mainland	Northern Interior	Southern Interior	Vancouver Island	Grand Total
2015	16,809	8,681	7,627	1,159	34,276
2020	41,707	20,903	18,563	2,665	83,837
2025	51,735	27,468	21,374	3,399	103,976
2030	64,876	35,357	26,607	3,969	130,809
Savings 2030 Relative to Total 2030 Savings	50%	27%	20%	3%	100%

5.4 Summary of Findings

The study findings indicated that even with a declining load there are significant potential cost-effective natural gas efficiency improvements in the Industrial sector. This potential is due to the existence of older inefficient boilers, lumber kilns, lime kilns, and a variety of other industrial process equipment that could be economically replaced. It would be cost effective for this replacement to occur by 2015, but due to other market barriers, it is estimated that in the *most likely* scenario and *aggressive* scenario it will take until 2030 to obtain the savings.

The major market barriers constraining faster market penetration include:

- Higher capital cost of efficient product(s)
- Need to recover investment costs in a short period (payback)
- Lack of product performance information
- Lack of available product.

In the *most likely* and *aggressive* Achievable scenarios these energy-efficiency improvements would provide between 2,010,000 and 2,725,000 GJ/yr. of savings in 2030 as well as peak day load reductions of approximately 16,990 to 23,080 GJ.

A variety of efficient boiler technologies accounts for nearly 57% of the total energy savings in the two Achievable Potential scenarios. The major opportunity involves replacing standard efficiency boilers in the 68% to 80% efficiency range with condensing boilers in the plus 90% efficiency range. This opportunity is mainly applicable to medium size boilers in the food processing and manufacturing sectors.

For large boilers, such as in pulp mills, and for large process equipment such as cement kilns, lime kilns and coal driers, the *most likely* opportunities will involve upgrading the equipment with better controls or heat recovery equipment rather than replacing the complete unit.

Another significant energy saving opportunity is improving the air heating efficiency of large industrial fabrication work spaces. Generally, these spaces are now heated with unit heaters. In some cases, inefficient unit heaters could be replaced by more efficient unit heaters but a larger opportunity is with replacing the unit heaters with gas radiant heaters.

6 Economic Impacts

6.1 Introduction

In addition to energy savings, FortisBC's investment in DSM programs can have broad impacts on the provincial economy as measured through metrics such as employment, GDP, and industrial output. Impacts arise from short term investment activities, such as building retrofits, and longer term changes in household/business spending, which can be attributed to the persistence of energy savings.

This analysis uses the results from the FortisBC Conservation Potential Review (CPR) Update 2010 to provide an estimate of the net macroeconomic impacts expected from implementing the *most likely* and *aggressive* Achievable Potential scenarios outlined in each of the main sector reports.

Three sets of economic impacts are reported in this analysis:

- Changes in output (total industry revenues)
- Changes in GDP at factor cost (total value added at producers' prices, or total output minus costs of production)
- Changes in employment (number of jobs).[5]

The above economic impacts are reported for three sectors (Residential, Commercial and Industrial) under the *most likely* and *aggressive* Achievable Potential scenarios at two milestone years: 2021 (10 years out) and 2030 (19 years out).

6.2 Approach

The economic analysis is based on the application of economic multipliers, which are a set of proportionality constants that relate changes in domestic production in a particular sector to its impacts on the entire B.C. economy. BC Stats released a report in March 2008 documenting the British Columbia provincial economic multipliers based on 2004 economic data. These multipliers were applied to various activities across all sectors from the energy-efficiency strategy and totalled to determine the net impacts, which are relative to the scenario where no energy-efficiency strategy is implemented.

6.3 Results and Conclusion

The study concludes that:

- The impacts on output, GDP, and employment are all positive across all sectors for every scenario
- Impacts increase over time and are larger for the *aggressive* Achievable scenario
- The Residential sector, in every scenario, accounts for the greatest share of economic impacts
- By 2021, the net employment gains from CPR activities will range between 362 - 682 jobs, depending on the scenario
- By 2031 the net employment gains from CPR activities would grow to between 580 - 881 jobs, depending on the scenario.

[5] BC Stats and BC Ministry of Advanced Education and Labour Market Development (2010). *A Guide to the BC Economy and Labour Market.*

Exhibit 39 and Exhibit 40 present a summary of the impacts in the milestone year 2021 for the *most likely* and the *aggressive* Achievable Potential scenarios. Additional results are provided in the main report.

Exhibit 39 Economic Impacts, 2021, Most Likely Achievable Scenario

Sector	Output	GDP	Employment
Residential	$31,935,141	$9,173,163	197
Commercial	$11,419,118	$3,211,087	118
Industrial	$4,545,079	$1,212,245	47
Total	$47,899,339	$13,596,496	362

Exhibit 40 Economic Impacts, 2021, Aggressive Achievable Scenario

Sector	Output	GDP	Employment
Residential	$72,915,818	$20,923,741	441
Commercial	$16,260,403	$4,592,314	166
Industrial	$7,328,959	$1,951,239	75
Total	$96,505,181	$27,467,294	682

222 Somerset Street West, Suite 300
Ottawa, Ontario, Canada K2P 2G3
Tel: +1 613 523-0784
Fax: +1 613 523-0717
info@marbek.ca
www.marbek.ca

Project ID: 10041

Appendix K-3

TGI-TGVI 2009 EEC REPORT

Provided in electronic format only

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

March 31, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (collectively the "Companies")
Energy Efficiency and Conservation Program - 2009 Annual Report

British Columbia Utilities Commission (the "Commission") Decision dated April 16, 2009 and Order No. G-36-09 Compliance Filing

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On April 16, 2009, the Commission issued its Decision and Order No. G-36-09 (the "Decision") on the Companies Energy Efficiency and Conservation ("EEC") Application approving funding for TGI and TGVI for 2009 and 2010 programs.

In the Decision, the Companies were directed to file annual EEC Reports on all of the EEC initiatives and activities, expenditures and results by the end of the first quarter following year-end and for each year of the funding period.

Further funding for 2011 was approved for each of the Companies in their respective 2010-2011 Negotiated Settlement Agreements[1] approved by the Commission

Attached, pursuant to the Decision, the Companies respectfully submit their first annual EEC Report for 2009 (the "Report"). In the Report, the Companies seek the following from the Commission:

1. Acceptance of the 2009 EEC Report;
2. Approval of the attribution of savings from regulation to be on a case-by-case basis; and
3. Approval for the attribution of 6 years of post-regulation savings to a Condensing Water Heater Initiative.

---

[1] Negotiated Settlement Agreements approved on November 26, 2009 for TGI by Order No. G-141-09 and TGVI by Order No. G-140-09

If you have any questions regarding this submission please contact the undersigned or Sarah Smith, Manager, Marketing and Energy Efficiency at (604) 592-7528.

Yours very truly,

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed:

Tom A. Loski

Attachments

cc (email only): EEC Stakeholder Group

Terasen Gas Inc. and

Terasen Gas (Vancouver Island) Inc.

Energy Efficiency and Conservation Programs

2009 Annual Report

March 31, 2010

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1. REPORT OVERVIEW

1.1 Background

Terasen Gas Inc. ("Terasen Gas" or "TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (collectively referred to as "the Companies") have been involved with Energy Efficiency and Conservation ("EEC") since the 1990's. The Companies' earlier EEC activities were referred to in previous regulatory filings with the British Columbia Utilities Commission (the "Commission" or the "BCUC") as Demand Side Management ("DSM") activity.

Simply defined, EEC or DSM activity refers to activities designed to affect customers' use of natural gas – generally to encourage them to reduce their consumption. These programs have been successful in the past in promoting the efficient use of natural gas, encouraging the adoption of low carbon energy alternatives, reducing energy costs for customers, and supporting government policy by reducing greenhouse gas emissions ("GHGs"). Yet until recently the Companies' efforts were limited in terms of impact because of the relatively minimal funding allocated for EEC programs.

On May 28, 2008, TGI and TGVI collectively filed their Energy Efficiency and Conservation Programs Application (the "EEC Application"), seeking approval of increased funding of EEC programs for the timeframe of 2008-2010. On April 16, 2009, the Commission released its decision on the EEC Application and Order No. G-36-09 (the "EEC Decision"), which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI). On November 26 2009, the Commission released Orders G-141-09 and G-140-09 approving Negotiated Settlement Agreements ("NSAs") in the 2010 – 2011 Revenue Requirement Applications for TGI and TGVI respectively. The NSAs allocated a further $32.35 million in EEC expenditure for TGI, and $6.1 million for TGVI, to bring the total approved EEC expenditure to 2011 for both utilities to approximately $80 million.

This EEC Annual Report ("EEC Annual Report" or the "Report") outlines how the Companies are already using this additional funding to further EEC, and how they will continue to broaden and enhance these efforts in 2010-2011. As the Report will make clear, the Companies are making effective use of the newly available funds to promote EEC and support the province's goal of GHG reductions.

This report overview outlines the purpose of this Report and its content.

1.2 EEC Annual Report: Taking Stock of Progress, Taking Accountability

This Report serves two purposes.

First, this Report demonstrates that the Companies are meeting the accountability mechanisms included in their proposal to the Commission. One such mechanism was the requirement to file EEC Annual Reports as follows:

"A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI."[1]

Second, it reflects the Companies' commitment to taking stock of the success and progress of efforts to promote EEC since the Commission's EEC Decision. The Commission specified the following information be included in the EEC Annual Reports:

"The Commission panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

Commission Panel directs that the annual EEC Report include the following:

- *TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*

- *any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.*

- *data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.*

The Commission Panel also directs Terasen to include in its annual EEC Report to the Commission a discussion of its internal data gathering, monitoring and reporting control processes. The discussion should include a description of how these processes ensure that funds expended and the statistical results of the programs implemented are completely and accurately recorded and monitored, including any related internal check and audit processes. The report should also discuss how Terasen has measured or estimated the results of the EEC expenditure initiatives."[2]

The Commission also directed the Companies to redesign and resubmit the Attribution to Regulatory Change with its next EEC Annual Report, "reflecting the provisions of the DSM regulation which come into effect for [the Companies] on June 1, 2009"[3] (please refer to Section 8).

The Companies believe that the details contained in this EEC Annual Report satisfy the requirements of the EEC Decision.

1 EEC Decision, page 2

2 Ibid, page 42

3 Ibid, page 40

1.3 Organization of the EEC Annual Report

This Report is a comprehensive overview of the Companies' efforts to seek funding for, and then to resource, design and implement a comprehensive EEC initiative in 2009 and beyond. It officially serves as the EEC Annual Report for 2009; it also identifies the Companies' plans for EEC activities in 2010. Collectively these sections (and this EEC Annual Report) demonstrate that the Companies are developing and carrying out an effective portfolio of EEC Programs and associated activities.

This Report includes the following sections:

2. A History of Commitment to DSM

This section outlines the Companies' long-standing commitment to DSM activities, despite a comparatively low level of funding. The fact that the Companies have historically been engaged in DSM efforts will help to ensure that the transition to a broad, robust EEC portfolio is a smooth one.

3. Appropriate Resources: Financial and Human

In this section, the Companies describe the funding requested for EEC activities and the amounts approved by the Commission. It details how these funds are necessary for the Companies to create the kind of robust EEC plan that will reshape customer behavior. The section also details how the Companies have established a well-resourced EEC team and how external consultants will be used to supplement that team's expertise.

4. 2009 Activities: Establishing the EEC Foundation

This section details how the Companies have developed a comprehensive EEC Portfolio of programs with associated activities. It will outline that while 2009 and early 2010 were collectively a transition period, the Companies used this time to launch programs that have already delivered value to stakeholders.

5. 2010 Plan: Building on the EEC Foundation

This section outlines how the 2010 EEC activity will build on the existing portfolio by adding several other programs and initiatives. These include High-Carbon Fuel Switching, Conservation for the Interruptible Industrial Sector, and Innovative Technologies.

6. Conservation Potential Review ("CPR")

In this section, the Companies describe their plans for conducting an update to the 2006 CPR in 2010 to establish the basis for EEC funding in 2012 and beyond.

7. Sound Internal Controls and Reporting Mechanisms

This section outlines the data collection plan and business practices the Companies have put in place for EEC activities to ensure that these activities are in compliance with the general controls of the Company.

8. Market Transformation and Attribution

This section recognizes the Companies' leadership role related to the introduction of Regulated Standards and their commitment to undertake activities which encourage and support Market Transformation. The Companies also set out their proposal for the attribution of savings from regulation to be attributed to utility programs on a case-by-case basis.

1.4 Summary

The Companies have a long history of delivering successful DSM and EEC programs efficiently and effectively, which have brought value to stakeholders, while providing energy savings and GHG reductions.

Now that the Commission has granted increased funding to the Companies, both the scope of EEC efforts and their impact has increased significantly. This Report outlines these successes and how they lay the groundwork for an ongoing EEC campaign.

1.5 Approvals Sought

The Companies respectfully request the following from the Commission:

1. Acceptance of the 2009 EEC Annual Report; and
2. Approval for the attribution of savings from regulation to be on a case-by-case basis as outlined in Section 8; and
3. Approval for the attribution of 6 years of post-regulation savings to a Condensing Water Heater Initiative, as described in Section 8.

A draft form of Order is provided in Appendix K.

2. A HISTORY OF COMMITMENT TO DSM

The EEC Program approved by the Commission and launched by the Companies in 2009 builds upon a legacy of commitment to DSM. Despite limited funding, TGI has, since 1997, created and carried out DSM programs. TGVI also has a track record of managing DSM programs (i.e. fuel switching, load building). This experience and understanding of DSM priorities serves as an important foundation for the Companies' expanded efforts.

This section outlines the Companies' proven commitment to DSM (and now EEC).

2.1 Historical EEC Activities Overview: 1990s - 2008

The Companies have a track record of being committed to DSM and EEC initiatives.

Since 1997, TGI has delivered value to its customers through DSM initiatives. These began on July 23, 1997 when TGI received approval from the Commission for its 1998-2002 Revenue Requirements Application. In this Application the Commission endorsed a mechanism to pursue DSM resources.

On July 29, 2003, by Order No. G-51-03, TGI received approval from the Commission for a Multi-Year Performance Based Rate Plan Settlement Agreement (the "PBR Settlement Agreement") for the period 2004-2007. This PBR Settlement Agreement was extended by the Commission, by Order No. G-33-07, for the 2008-2009 period.

EEC funding levels were established at approximately $1.50 million per year for incentives with funds being placed in a deferral account and amortized over three years. Additionally, non-incentive expenses of approximately $1.624 million per year were treated as Operations and Maintenance ("O&M") expense and were expensed in the year incurred.

TGVI too has a history of pursuing DSM efforts.

Since its inception TGVI has successfully delivered load building and fuel switching programs, delivering value for both customers and TGVI despite the limited funding available. Historically, TGVI's DSM activities were aimed at employing marketing programs to attract new customers and add load in order to improve the utilization of the gas delivery system on Vancouver Island.

TGVI's efforts became more formal and developed when in 2005 TGVI received approval from the Commission for the 2006-2007 Negotiated Settlement Agreement, through which DSM expenditures were approved. In addition, the Commission approved the two-year extension of the Negotiated Settlement Agreement terms for 2008 and 2009 by Order No. G-34-07, which included approval for DSM expenditures.

TGVI has historically had DSM expenditures of approximately $650,000 per year for incentives, plus $500,000 per year for non-incentive costs. For TGVI, incentive expenditures were placed in a deferral account and fully amortized the year following incurrence and non-incentive costs were treated as O&M and were expensed in the year incurred.

In summary, despite the relatively low level of funding and resources available up until 2008, TGI and TGVI delivered cost-effective programs bringing value for stakeholders.

3. THE RIGHT RESOURCES: FINANCIAL AND HUMAN

The Companies' EEC efforts depend on having access to the requisite resources to create and execute a broad portfolio of initiatives. As this section demonstrates, through 2011, the Companies have access to a level of funding that will allow the Companies to deliver the EEC activities identified in the EEC Application. As well, the Companies have established an initial organizational structure that will enable delivery of most of the initiatives identified in the EEC Application. This section describes funding approvals for EEC activity through 2011, and the Companies anticipate filing a request for continued funding for EEC activity for 2012 and beyond early in 2011. The long-term success of the Companies' EEC activity and efforts to support market transformation is dependent on continued stable, secure funding for EEC initiatives.

3.1 Appropriate Funding: 2008-2010

On May 28, 2008, TGI and TGVI collectively filed their Energy Efficiency and Conservation Programs Application (the "EEC Application"), seeking approval of increased funding of EEC programs for the timeframe of 2008-2010. The EEC Application requested approval for total funding of $56.6 million over three years ($46.944 million for TGI and $9.667 million for TGVI), deferral treatment by charging the expenditures to a regulatory asset deferral account with an amortization period of 20 years, and a portfolio methodology for evaluating the costs and benefits of the overall EEC portfolio.

On April 16, 2009, the Commission released its Decision and Order No. G-36-09 (the "EEC Decision"), which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI).

This funding represented a significant increase from what had been previously allocated for DSM activities and ensures the Companies have the financial resources to execute on proposed EEC initiatives between 2008 and 2010.

Specifically, the following proposed expenditures were accepted:

(a) $31.077 million for the combined Residential Energy Efficiency and Commercial Energy Efficiency programs;

(b) Expenditures for programs or initiatives directed at fuel switching away from fossil fuels which have a higher carbon content than that of natural gas;

(c) $6.918 million for Conservation, Education and Outreach;

(d) $3.0 million for Joint Initiatives; and

(e) $0.5 million for a Conservation Potential Review.

The Commission also approved deferral treatment of all expenditures with an amortization period not to exceed 10 years, and approval of a portfolio approach to evaluating the costs and benefits of the overall EEC portfolio.

The above funding approvals from the Commission provided the Companies with the financial resources they required to create and launch a portfolio of EEC programs that have already begun to deliver value to customers while supporting provincial goals of promoting conservation and reducing GHGs. The programs and their impact to date are described in more detail in Section 4.

3.2 Funding for the Future: 2010 and 2011 EEC Funding

In June 2009, both TGI and TGVI filed their respective 2010-2011 Revenue Requirements Applications. In these applications the Companies sought, among other things, to:

- Increase EEC funding to add programs for Interruptible Industrial customers (TGI only) and Innovative Technologies;
- Reallocate approved funding to add to Affordable Housing; and
- Extend to 2011 the programs and funding approved by the Commission in the EEC Decision.

The expenditures for conventional energy efficiency for 2011 were set to match the forecast expenditures for 2010. Furthermore, the same portfolio-level Total Resource Cost ("TRC") approach as that which was approved in the EEC Decision was used to analyze and assess EEC expenditures.

When the Commission approved TGI's and TGVI's NSAs[4], this included the approval of EEC funding for TGI and TGVI for 2010 and 2011. This funding (summarized in Table 3-1) ensures that TGI and TGVI will have access to requisite funding for continued EEC activities in the 2010 to 2011 period.

Table 3-1: TGI and TGVI EEC Approved Funding for 2010 and 2011

	TGI		TGVI	
($000s)	2010	2011	2010	2011
Residential and Commercial Programs	23,075	23,075	4,726	4,726
Affordable Housing	2,400	2,400	600	600
Industrial Interruptible	435	1,875	-	-
Innovative Technologies	2,300	4,669	478	956
Total	**28,210**	**32,019**	**5,804**	**6,282**

As a result of the additional approved funding through their respective NSAs, the Companies have greater flexibility and funding available to continue to offer energy savings activities to customers through 2011.

3.3 Resources and Staffing

The Companies were effective in delivering DSM initiatives from 2005 to 2008 through their Marketing and EEC team. As a result of the increased EEC funding approved in the EEC Decision, the Companies have restructured their Marketing and EEC teams to add the

[4] For TGI Order No. G-141-09 and for TGVI Order No. G-140-09, both dated November 26, 2009.

resources necessary to effectively deliver the EEC programs. The Companies will manage the EEC resource requirements as necessary, on an ongoing basis, to efficiently and effectively develop, implement and deliver the portfolio of EEC activities and programs.

The following sections outline the structure of the Companies' internal and external resources designed to optimally deliver the EEC programs.

3.3.1 Resources and Staffing Expenditures

As discussed earlier in Section 2, TGI and TGVI have historically been able to deliver a certain level of energy savings to customers by delivering EEC programs with relatively few resources.

The Companies drew on the experience it had developed in these earlier, successful DSM/EEC initiatives to determine how to best allocate its resources. Careful consideration was given to where to allocate funding.

Table 3-2 below provides a resource view of the EEC expenditures for 2009.

Table 3-2: Resource View of EEC Expenditures for 2009 ($000)

	TGI	TGVI	**TGI & TGVI**
Labour Costs	854	15	869
Non-Labour Costs	4,750	453	5,203
Employee Expenses/Supplies	167	15	182
Incentives, Program Admin Costs & Fees	3,667	86	3,753
Promo & Advertising	642	344	986
Contractor Costs	274	8	282
Total Costs	**5,604**	**468**	**6,072**

3.3.2 Staffing for EEC: Assembling the Right Internal Resources

The EEC team was built on a small but strong foundation. Prior to the EEC Decision, the Marketing and Energy Efficiency team consisted of four core staff members including a DSM Lead, a Marketing Program Specialist and a Program Specialist all reporting to the Manager of Marketing and Efficiency. Additional support for the DSM activities was provided by the Technical Sales Support staff, the Commercial and Industrial Account Management team, and the Residential New Construction Account Management team, on a part-time, as needed basis.

In order to deliver on the programs and activities approved in the EEC Decision, the Marketing group went through an extensive organizational structure change to put in place a cohesive team for the development and execution of the EEC initiatives.

Much of the group's time in 2009 was spent on recruiting, hiring and training the staff the Companies would need in order to successfully deliver the activities approved in the EEC Decision. A recruiting process commenced after the EEC Decision for approximately three months duration. The following additional positions were established and filled in 2009 to support the EEC activities and programs:

- EEC Program Manager Residential
- EEC Program Manager Commercial
- EEC Program Manager Affordable Housing
- EEC Program Manager Conservation, Education and Outreach
- EEC Program Manager Qualified Dealer
- Marketing Program Specialist Residential
- Marketing Program Specialist Commercial
- Marketing Program Specialist Conservation, Education & Outreach
- Marketing Program Specialist Affordable Housing
- Energy Technology Specialist
- EEC Communications Coordinator
- EEC Administration Assistant

The new structure of the Marketing and EEC team for 2009 is designed and effectively resourced to deliver on the expanded portfolio of EEC programs the Companies must deliver.

3.3.3 2010 Internal Resources: Continuing to Develop Organizational Capability

For 2010, the Companies are anticipating the necessary addition of EEC Program Managers for Innovative Technologies, Interruptible Industrial and Customer Financing. At this time, the labour budget for the EEC activities for 2010 is estimated at $1.545 million. The structure of the EEC team for 2010 may change over the course of the year as new opportunities and activities are identified and deployed. Additional staff and changes in reporting structure may need to be put in place in order for the Companies to continue to deliver the expanded Portfolio of EEC Programs.

3.3.4 Staffing for EEC: Drawing on the Right External Resources

While the EEC team provides the primary resources for design, implementation, administration and delivery of the EEC programs, for specific or specialized EEC activities, the Companies also engage the services of outside consultants. These consultants are engaged to supplement internal resources and expertise. External consultant resources are used to support certain activities on an as-required basis determined by the business needs.

The following is a summary of the primary external consultants used and the services for which they are typically engaged.

- Habart and Associates: The Companies have been working with Habart and Associates ("Habart") consulting firm for a number of years. In 2009, Habart provided support and services on a number of projects, including a DSM training seminar for the new members of the EEC team, Information Requests ("IRs") support, furnace program billing analysis (in partnership with John Sampson Research), estimation of energy impacts for program measures as well as several other projects.

- Willis Energy Services ("Willis"): Willis is another long-term external consultant who has provided the Companies with consulting and support of the DSM models as well as support with answering IRs specific to these models.

- KnowledgeTech Consulting ("KnowledgeTech"): The Companies have also engaged KnowledgeTech, whose Information Technology ("IT") expertise was used to assist with the Demand Side Management System ("DSMS"). The DSMS addresses the requirement for more robust program tracking and reporting. More information about the DSMS can be found in Section 7.1.

In addition to the consultants mentioned above, the EEC team hired several other consultants to assist with program evaluation, market research projects and specific requests. The details of this activity are provided under the Enabling Activities sections, Section 4.8 for 2009 and Section 5.13 for 2010.

3.4 Resources: Conclusion

The April 16, 2009 Commission approval of funding in aggregate of $41.5 million and subsequent approval of TGI and TGVI's 2010-2011 NSAs (and associated 2010 and 2011 EEC funding) ensured the Companies would have access to the financial resources so that programs could be launched for the benefit of customers.

Drawing on these funds, the Companies have since developed and structured the appropriate internal team to carry out their mandate. Further, the Companies have prudently engaged external consultants where appropriate to draw on expertise.

The resources that are now in place ensure the Companies are appropriately positioned to develop, implement and deliver the expanded portfolio of EEC activities and programs.

4. 2009 ACTIVITIES: ESTABLISHING THE EEC FOUNDATION

Following the EEC Decision in April of 2009, the Companies set out to establish a foundation that year for broader EEC programs. The primary focus of 2009 (a "transition" year) was building the EEC team described in Section 3.

While most programs and activities did not get underway until the second half of 2009, the results achieved in this short time demonstrate successful execution of an expanded EEC portfolio and programs.

This section will elaborate on this by examining at a high level:

- 4.1 EEC Program Portfolio and Associated Program Areas: Growing Scope
- 4.2 2009 Portfolio & Program Results – Delivering Value While Laying Foundation

Then this section continues with program specific details as follows, looking in detail at how the Companies pursued EEC objectives through:

- 4.3 Residential Energy Efficiency Programs
- 4.4 Commercial Energy Efficiency Programs
- 4.5 Conservation for Affordable Housing Programs
- 4.6 Joint Initiatives
- 4.7 Conservation, Education and Outreach Programs
- 4.8 Enabling Activities
- 4.9 EEC Stakeholder Group Activities
- 4.10 Summary 2009 EEC Activities: Successfully Establishing the Foundation

The results reflect a partial year of activity for 2009 as most of the programs were rolled out in the second half of 2009 once the EEC Decision was issued and the staffing resources were set in place; these results are for programs where activities were performed in 2009 and where the related program expenditures may continue to occur in 2010.

Yet despite the relatively short time frame in which they have been launched, these programs are already delivering value to customers while furthering the province's goals around GHGs reduction and the promotion of conservation.

4.1 EEC Program Portfolio and Associated Program Areas: Growing Scope

The Companies' EEC Portfolio consists of multiple Program Areas. Each Program Area includes all specifically related programs, measures and activities. While the Companies had an EEC Portfolio for many years, the limited funding meant the scope of the Portfolio was limited. With the Commission's approval of additional funding (see Section 3.1), the groundwork was laid to expand the Portfolio.

As might be expected, EEC activity in 2009 experienced a considerable expansion in all Program Areas. Furthermore, a new Program Area was created for Conservation for Affordable Housing, in order to recognize its importance and profile within the Companies' EEC activity.

Also created were two additional non-Program Area specific sections related to the EEC Portfolio:

- Enabling Activities (activities that are supportive of the Companies' EEC program development and delivery) and
- EEC Stakeholder Group Activities (the work achieved with the EEC Stakeholder Group in 2009).

Further information for each Program Area and Activity can be found in subsequent sections of this Report.

4.2 2009 Portfolio and Program Results: Delivering Value While Laying Foundation

Considering that the Companies' expanded EEC activity did not get underway until late Q3 when the additional EEC staff had been hired and trained, the overall portfolio results are reasonable.

Table 4-1 below shows overall program results including the overall incentive and non-incentive amounts spent on EEC programs, annual energy savings, Net Present Value ("NPV") of the energy savings over measure life, and the TRC results. For 2009, the overall EEC portfolio achieved close to 1.3 million Gigajoules ("GJs") in measure life energy savings which is considerably higher than the measure life energy savings achieved in 2008 (612,651 GJs).

Table 4-1: 2009 Overall Portfolio Results Brought Value to Customers and the Companies

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
TGI	3,245	2,498	5,743	125,267	1,223,559	1.2
TGVI	98	419	518	5,698	60,541	0.8
Total Results	3,344	2,917	6,261	130,965	1,284,100	1.2

The TRC results for TGI are at 1.2 and for TGVI are at 0.8 and the overall Portfolio TRC results are 1.2, so the overall Portfolio result complies with the Commission's acceptance of the Companies' proposal regarding Portfolio level TRC of greater than one to be considered cost-effective. The 2009 TRC result for TGVI was 0.8. This is because programs for TGVI were halted in 2007, pending submission and approval of the EEC Application and only restarted in Q2 of 2009 once the EEC Application was approved. Thus the programs for TGVI in 2009 had very little opportunity to gather momentum in terms of participation rates, leading to a lower TRC. The Companies anticipate that over the course of 2010, participation in programs on TGVI will increase as the market becomes more aware of the availability of EEC initiatives for TGVI. Note the difference between the Total for Incentive and Non-Incentive Expenditure ($6.261 million) shown in the table above, and the Total Costs ($6.072 million) in the Table 3-2 of Section 3.3.1 is $188,306. This is because the latter figure ($6.072 million) is based on the actual expenditures in 2009, while the former figure ($6.261 million) is based on the amounts associated with each 2009 program that might be incurred in 2010, thus providing a more complete view of individual program costs.

The value delivered through these early Portfolio efforts can be seen in more detail when the results are presented by Program Areas. These results are shown below in Table 4-2. Further details on cost-benefit analysis can be found in Appendix J.

Table 4-2: 2009 Expanded Program Areas Brought Value to Customers and the Companies

Program Area	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
Residential Programs	**2,022**	**166**	**55,031**	**574,607**	**1.2**
TGI	1,975	138	52,901	553,543	1.2
TGVI	47	28	2,130	21,063	1.4
Commercial Programs	**925**	**147**	**74,373**	**693,352**	**2.1**
TGI	874	140	70,804	653,874	2.1
TGVI	51	7	3,569	39,478	2.0
Conservation for Affordable Housing (TGI & TGVI)	**390**	**0**	**1,352**	**14,236**	**0.7**
Joint Initiatives (TGI & TGVI)	**7**	**428**	**210**	**1,905**	**0.8**
Conservation, Education & Outreach (TGI & TGVI)	N/A	**612**	N/A	N/A	N/A
Enabling Activities (TGI & TGVI)	N/A	**266**	N/A	N/A	N/A
Other Portfolio Level Activities (TGI & TGVI)*	N/A	**1,298**	N/A	N/A	N/A
Total	**3,344**	**2,917**	**130,965**	**1,284,100**	**1.2**

*Other Portfolio Level Activities include research & evaluation, consultants' fees, non-program administation activities & labour

Note that the Companies have created a discrete Program Area specific to Conservation for Affordable Housing, moving it out of the Joint Initiatives Program Area in order to recognize its importance, which was emphasized in the EEC Decision and the NSAs. Further, the Companies have specifically allocated $3 million annually to Conservation for Affordable Housing for 2010 and 2011, so the budget for this Program Area is considerable.

As shown in the Table 4-1 and 4-2 above, the EEC portfolio in 2009 brought value to customers and the Companies. The details of each Program Area are further discussed in the following sub-sections and more comprehensive program details can be found in Appendix D.

In 2010, the EEC team will further expand the program portfolio by building on the existing programs and by adding three Program Areas, the details of which are discussed in Section 5. Overall, the EEC Portfolio delivered value for customers in 2009, as measured by a Portfolio-level TRC of 1.2.

This Report will now examine each of the programs and activities through which the Companies pursued EEC objectives in 2009; these programs and activities also serve to lay the foundation for broader work and greater results in 2010 and beyond.

4.3 Residential Energy Efficiency Programs

Residential Energy Efficiency programs are offered in TGI and TGVI service areas. For EEC purposes, residential customers include end-use customers living in a residential single-family home, row house, townhouse or mobile home.

4.3.1 Program Goals

Residential Energy Efficiency programs encourage households to reduce their overall consumption of natural gas and help to manage their energy bills.

In addition to saving energy, Residential Energy Efficiency programs focus on the following objectives:

- Prepare the market for adoption of new energy efficient technologies through incentives, and support of government regulations;
- Upgrade existing low efficiency systems to capture energy savings associated with reducing the overall consumption of natural gas;
- Educate the trades community about upcoming regulations and gain an understanding of technical requirements or other barriers associated with new product introductions;
- Educate consumers about the advantages of energy efficient furnaces and boilers and provide incentives for their adoption when necessary;
- Engage manufacturers by supporting new technologies and provide advertising opportunities to the Companies customer base;
- Develop cost-effective programs with a TRC greater than 1.0 that optimize the proportion of incentives over administration and marketing costs; and
- Conduct program evaluation that confirms savings claims and guides program development of future programs.

4.3.2 Two Retrofit Programs in the Market

There were two Residential Energy Efficiency retrofit programs offered in 2009: the ENERGY STAR® Heating System Upgrade Program, which includes participants from the provincial government's LiveSmart BC Residential Retrofit Incentive Initiative, and the EnerChoice Fireplace Program.

Table 4-3 provides a summary of the 2009 Residential Energy Efficiency programs for TGI and TGVI. The ENERGY STAR® Heating System Upgrade Program surpassed its original target of 8,180 heating systems, achieving 7,930 by December 31, 2009 with the expectation of achieving 15,000 upgrades once all applications are processed in 2010. The EnerChoice Fireplace program, although program participation numbers were less than expected, achieved its primary objective of education and outreach about the importance of energy efficient fireplaces.

Table 4-3: 2009 Residential Energy Efficiency Programs for TGI and TGVI are cost effective and deliver substantial energy savings

	Program	Description	Retrofit			
			Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TRC	
					TGI	TGVI
1	ENERGY STAR® Heating System Upgrade	$250 Incentive for upgrading heating system to ENERGY STAR® rated appliance	1,233	299,201	1.1	0.9
	ENERGY STAR® Heating System Upgrade - LiveSmart BC	$250 Incentive for upgrading heating system to ENERGY STAR® rated appliance as part of LiveSmart BC incentive portfolio	871	231,121	1.2	1.2
2	EnerChoice Fireplace	$50 Dealer Incentive to promote and educate customers about Energy Efficient Fireplaces	84	44,285	2.6	2.4

The highlights of the 2009 Residential Energy Efficiency programs are as follows:

- The ENERGY STAR® Heating System Upgrade Program, including participants from LiveSmart BC, will surpass the replacement target of 8,180 furnaces or boilers outlined in the EEC Application, upon completion of application processing in 2010. The program will achieve energy savings of 530,322 GJs over the life time of the measure. The program achieved a TRC of 1.1 in TGI and 1.0 in TGVI. This demonstrates that the program is cost-effective and has substantial energy savings over the lifetime of the measure.

- The EnerChoice Fireplace Program encouraged dealers to educate consumers about the merits of energy efficient fireplaces through a $50 sales promotion incentive ("SPIFF")[5]. Participant numbers were lower than the 2008 program because dealers found the SPIFF application process to be onerous during their peak sales season. The program achieved energy savings of 44,285 GJs over the life time of the measure. The program achieved a TRC of 2.6 in TGI and 2.4 in TGVI. Although the program's projected energy savings goals were not met, the education and outreach objectives of the program were met. Since EnerChoice education for dealers has been met, the 2010 program will involve consumer incentives.

[5] A Sale Promotion Incentive Fund, or SPIFF, is an incentive directed to a salesperson for selling a specific product. For the purpose of the EnerChoice Fireplace program, sales people were eligible for a $50 rebate cheque for each EnerChoice fireplace they sold.

Residential Energy Efficiency programs are described in further detail below.

4.3.3 ENERGY STAR® Heating System Upgrade Programs

Program Area:	Residential Energy Efficiency Programs
Target Market:	Retrofit
Duration:	TGI: Sep 1, 2008 through Dec 31, 2009 TGVI: April 16, 2009 through Dec 31, 2009
Incentives:	$250 bill credit Manufacturer's coupons September through December, 2008 and 2009
Partner:	LiveSmart BC Residential Retrofit Incentive Initiative

Program Administration:

Accenture Utilities Business Process Outsourcing Services ("ABSU"), a subsidiary of Accenture Inc., through a subcontracting arrangement with CustomerWorks LP.

Program Objectives:

- Upgrade a minimum of 8,180 heating systems;
- Prepare market for adoption of ENERGY STAR® provincial furnace regulations for retrofit market, January 1, 2010;
- Educate the trades community about upcoming regulations;
- Educate consumers about the advantages of energy efficient furnaces and boilers and provide an incentive that promotes a proactive replacement decision;
- Engage manufacturers by distributing coupons for ENERGY STAR® furnaces and boilers and providing funds for co-marketing opportunities; and
- Develop a cost effective program with TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.

Background:

The Companies have maintained ENERGY STAR® Heating Upgrade programs in the market since 1996. The most recent iteration of the ENERGY STAR® Heating System Upgrade Program was launched September 1, 2008 in the TGI service territory and April 16, 2009 in the TGVI service territory.

The program offered a $250 bill credit to partially offset the estimated $850 incremental cost of purchasing ENERGY STAR® furnaces or boilers over mid-efficiency models. In addition to the $250 incentive, from September to December, 2009 furnace and boiler manufacturers provided coupons for discounts and extended warranties for ENERGY STAR® heating systems.
The primary program objective was to reap the energy savings associated with upgrading low or mid-efficiency heating systems. In addition, the program focused on preparing the market for

January 1, 2010 changes to the BC Energy Efficiency Act Standards for gas furnaces outlined in the Ministry of Energy Mines and Petroleum Resources ("MEMPR") Enforcement Bulletin 09-03[6]. The regulated energy efficiency standard for these products is an Annual Fuel Utilization Efficiency ("AFUE") equal to or greater than 90%. These regulations took effect for new residential construction on January 1, 2008 and for replacement furnaces in existing dwellings on December 31, 2009. The BC provincial regulation changes align with Natural Resources Canada ("NRCan") regulations for new and existing buildings across Canada. Significant outreach to consumers, trades and manufacturers helped facilitate the industry's transition to the new regulation.

Please refer to Appendix D for detailed program description.

Results:

As of December 31, 2009, the number of participants to date was 7,930 with expectations of achieving over 15,000 participants once final applications are processed in 2010. Given that the goal for program participation in the EEC Application was 8,180, this program has been extremely successful with participation surpassing that goal.

Table 4-4 provides program highlights of the ENERGY STAR® Heating System Upgrade Program performance metrics for 2009 including number of participants, incentives to non-incentives spending, net annual energy savings, and the savings over the lifetime of the measure. The free rider rate suggests that 43% of participants may have upgraded their appliance without the incentive, so this proportion of participants has been backed out of the energy savings. The positive TRC indicates that there are positive energy savings within a cost-effective program.

[6] Please refer to Appendix C for a copy of the MEMPR Enforcement Bulletin 09-03.

Table 4-4: ENERGY STAR® Heating System Upgrade Program Performance Summary illustrates that programs are cost effective and deliver substantial energy savings

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
The Companies	TGI	4,391	1,098	101	27,882	293,682	43%	1.1
	TGVI	83	21	14	527	5,519	43%	0.9
LiveSmart BC	TGI	3,391	848	7	21,532	226,799	43%	1.2
	TGVI	65	16	-	413	4,322	43%	1.2
Total	**TGI**	**7,782**	**1,946**	**108**	**49,414**	**520,482**	**43%**	**1.1**
	TGVI	**148**	**37**	**14**	**940**	**9,840**	**43%**	**1.0**

Note: The Companies Participation Rates are based on the number of bill credits issued as of December 31, 2009 including 371 bill credits that were issued in 2008 that were not included in previous program reports.
The LiveSmart BC participant numbers were based on number of furnaces invoiced as of Dec 31, 2009.

In 2009, $1.98 million in incentives were distributed. Total spend for non-incentive dollars was $122,000. Notably, non-incentive spending represented only 6% of total spending. This demonstrates that the most significant portion of the program's expenditures are going towards incentives and that program administration and marketing are very cost effective.

As outlined in Table 4-4 above, based on 2009 participants, the program is achieving annual gas savings of 50,354 GJ's and 530,322 GJ's over the life time of the measure.

The Free Rider Rate used for this analysis was 43% based on customer feedback from the extensive 2005-2007 Furnace Program Evaluation (refer to Appendix D) that surveyed consumers and contractors. The 2005-2007 Furnace Program evaluation highlighted additional program benefits of a 30% spillover and noted that customers were advancing their purchase decision an average of 2.3 years. The additional energy savings benefits from spillover are not included in the program's TRC calculations, thus the TRC reported is conservative.

TRC results were 1.1 for TGI and 1.0 for TGVI. The TGVI TRC is slightly lower due to lower participant numbers as the program was introduced over seven months later than the TGI program. In addition, the TGVI opportunity for furnace replacement is lower due to the fact that there is newer furnace stock since natural gas service was first introduced to Vancouver Island in 1990.

For cost benefit analysis please refer to Appendix J.

Summary:

The most recent iteration of the ENERGY STAR® Heating System Upgrade Program achieved its objectives in preparing the market for the introduction of provincial and federal regulations requiring the installation of ENERGY STAR® furnaces in 2010, in addition to replacing a significant number of furnaces resulting in energy savings. In wrapping up this program in 2010, it is anticipated that the Companies will have provided $3.75 Million in funding for 15,000 heating system upgrades since September 2008, a significant contribution to this industry, resulting in large energy savings impacts. The full program overview and results will be discussed in the 2010 EEC Annual Report.

The partnership with LiveSmart BC was very successful in terms of adding 3,456 participants in 2009 with an additional 3,835 projected to be processed in 2010. The LiveSmart BC Residential Retrofit Incentive Initiative, launched in May 2008 by the Provincial government, provided incentives to reward residential retrofits that saved energy and reduced GHGs. This high profile program was very successful attracting over 40,000 participants in 15 months. In order to receive the $250 Terasen rebate through LiveSmart BC homeowners were required to complete a home energy assessment with a Certified Energy Advisor, licensed by NRCan[7]. The data was transferred from NRCan to LiveSmart BC. LiveSmart BC then invoiced Terasen. The partnership with LiveSmart BC is discussed in greater detail in the Section 4.6.

Since regulations require that mid-efficiency furnaces can no longer be manufactured, but can still be sold, the Companies are monitoring mid-efficiency furnace inventory through communications with industry. The results of these stakeholder discussions will determine the market need for a 2010 ENERGY STAR® Heating System Upgrade early retirement program as outlined in Section 5.5.2.6. Such a program would have the additional benefit of proactive furnace replacement savings.

4.3.4 EnerChoice Fireplace Program

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: TGI and TGVI: Sep 1, 2009 through Dec 31, 2009

Incentive: $50 Sales Promotion Incentive Fund (“SPIFF”) for each fireplace sold

Manufacturer Coupons

Partner: Hearth Patio and Barbecue Association of Canada (“HPBAC”)

Program Administration:

HPBAC and EEC staff

[7] Home Energy Assessments for existing homes are provided by NRCan-certified Home Energy Advisors. The initial assessment is referred to as the D-visit and includes a detailed evaluation of the home’s energy efficiency levels, as well as various tests to determine air leaks and recommendations for retrofits that will improve the home’s energy efficiency rating. The second visit, referred to as the E-visit, measures energy performance after the recommended retrofits have been completed.

Program Objectives:

- Encourage the sale and installation of energy efficient heater style fireplaces to reap the associated energy savings;
- Further the education and awareness of the EnerChoice label to consumers and industry;
- Further relationships with manufacturers and distributors of natural gas fireplaces, through the HPBAC;
- Engage manufacturers by distributing coupons for EnerChoice fireplace discounts and accessories; and
- Develop a cost effective program with TRC greater than 1.0.

Background:

Promoting energy efficient fireplaces is an important component to EEC programs since natural gas fireplaces account for 13% of residential natural gas consumption (based on 2006 CPR findings). In addition, 85% of The Companies customers have at least one fireplace or heating stove, based on the 2008 Residential End Use Study ("REUS") findings. The Companies are encouraging their customers to adopt energy efficient gas fireplaces designed for heating rather than simply decorative fireplaces for ambience.

The Enerchoice Fireplace label is a Canadian label reserved for products that meet or exceed efficiency levels as determined by an independent committee managed by HPBAC. Since there is currently no ENERGY STAR® rating for natural gas fireplaces, and there are no pending standards from the U.S. Department of Energy, the Canadian fireplace industry has developed its own efficiency label, branded EnerChoice. The EnerChoice designation can only be applied to free-standing stoves with Fireplace Efficiency ("FE") 66% or higher, fireplaces that are 62.4% or higher and inserts that are 61% and higher.

Please refer to Appendix D for detailed program description.

Results:

The EnerChoice Fireplace Program achieved some positive results, and the Companies gained valuable insight into how to further improve and modify the program in 2010.

Table 4-5 provides program highlights of the EnerChoice Fireplace Program performance metrics for 2009, including number of participants, incentives and non-incentives spending, net annual energy savings, and the savings over the lifetime of the measure. The free rider rate suggests that 24% of participants may have selected an EnerChoice fireplace without the incentive, so this proportion of participants has been backed out of the energy savings. The positive TRC indicates that there are positive energy savings within a cost-effective program.

Table 4-5: EnerChoice Fireplace Program Performance Summary illustrates that programs are cost effective by their positive TRC and had a strong educational component as evidenced by the non-incentive spending component that was primarily marketing costs

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	592	30	31	3,487	33,062	24%	2.6
TGVI	202	10	14	1,190	11,223	24%	2.4

Note: Actual numbers are based on the number of SPIFF applications processed by March 1, 2010 to reflect 2009 overall program performance. The incentives are not in the 2009 actuals budget but presented as an adjustment.

Based on the 2008 program, the Companies projected a program participant goal of 1,200 although only 794 units were achieved. Dealers reported that they found the SPIFF application process to be onerous during their peak sales season. Based on this feedback, the 2010 program will be a consumer-based incentive.
In 2009, $40,000 in incentives was distributed while total spend for non-incentive dollars was $45,000, which is to be expected given that the primary objective of the program was education and outreach.

As outlined in Table 4-5, the program is achieving annual gas savings of 4,677 GJ's and 44,285 GJ's over the life time of the measure. The Free Rider Rate was 24% as used on former fireplace programs.

When total program spending is compared to the avoided cost of gas, positive TRC calculations were 2.6 for TGI and 2.4 for TGVI.

For cost benefit analysis please refer to Appendix J.

Planned Improvements For 2010

Enerchoice Fireplace program evaluation on the 2008 and 2009 programs will be conducted in 2010. Billing analysis will be conducted on a random sample of 2008 program participants to validate energy savings claims for EnerChoice appliances. An EnerChoice awareness survey to dealers is being proposed to determine the market penetration of EnerChoice education and awareness programs and gain feedback on future requirements for EnerChoice educational programs.

The EnerChoice Fireplace Program achieved its primary objective in encouraging dealers to educate consumers about the merits of energy efficient fireplaces, through a $50 dealer incentive. Although EnerChoice fireplace program participation numbers by dealers was down over 2008, education and awareness of energy efficient fireplaces was met, as demonstrated by industry feedback on the success of the manufacturers' coupon program. This could be an example of spillover since customers purchased EnerChoice through the awareness building aspects of the program, rather than the incentive itself. The result is a cost-effective program in terms of reduced expenditures on incentives, marketing and administration.

Dealers are well educated on the merits of the EnerChoice label through the Companies' 2008 and 2009 dealer incentive program. As a result, a consumer incentive program to promote the purchase of energy efficient fireplaces is under development. Please refer to Section 5.5.2.3 for a discussion of the Companies' planned 2010 activities for EnerChoice fireplaces.

4.3.5 Summary

Overall the 2009 Residential Energy Efficiency Programs were very successful. They engaged customers in upgrading appliances to capture energy savings, supported the introduction of new provincial regulations, and reached out to the trades community for education and program awareness. These programs exemplify the role that a utility can play in market transformation.

4.4 Commercial Energy Efficiency Programs

Commercial customers are comprised of a variety of different organizations, both private and public in nature. They consume anywhere from 100 to over 40,000 GJ/yr, and are provided service through various customer rate classes. Typical examples include small and large multi residential buildings, small businesses, retail stores, large commercial office space, schools and universities, government, hospitals, and manufacturing facilities.

Commercial Energy Efficiency programs are aimed at encouraging commercial customers to reduce their overall consumption of natural gas, and their energy costs. These programs are offered in TGI and TGVI service areas, to both New Construction and Retrofit applications. Program offerings for TGI and TGVI are identical, and there is little difference for new construction and retrofit participants.

4.4.1 Program Goals

Commercial Energy Efficiency programs focus on the following objectives:

- Upgrade existing low efficiency systems to capture energy savings associated with reducing the overall consumption of natural gas
- Prepare the market for the adoption of new energy efficient technologies through incentives, and support of government regulations.
- Educate commercial customers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary.
- Engage the trades community and manufacturers by supporting new, energy efficient technologies.
- Develop cost effective programs with a TRC greater than 1.0 that optimize the proportion of incentives over administration and marketing costs
- Conduct program evaluations that confirm savings claims and guide the development of future programs.

4.4.2 Three Commercial Energy Efficiency Offerings

Space heating accounts for approximately 75% of gas consumption in the commercial sector. Thus the Companies program offerings in this initial year of EEC activity are heavily oriented towards this end use. There were three Commercial Energy Efficiency programs offered in 2009:

- The Efficient Boiler Program,
- The Light Commercial ENERGY STAR® Boiler Program, and
- The Energy Assessment Program.

Table 4-6 provides a summary of the 2009 Commercial Energy Efficiency programs for TGI and TGVI.

Table 4-6: Solid performance from Commercial Energy Efficiency Programs in 2009

Program		Description	New Construction		Retrofit		TRC	
			Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TGI	TGVI
1	Efficient Boiler Program	Rebate program for high efficiency commerical boilers > 300 MBH Input	15	9,869	928	635,497	2.0	2.0
2	Light Commercial ENERGY STAR® Boiler Program	Rebate program for high efficiency commerical boilers < 300 MBH Input	-	-	52	35,589	3.3	-
3	Energy Assessment Program	No charge energy use assessments of commercial facilities	N/A	N/A	77	12,396	2.4	-

The highlights of the 2009 Commercial Energy Efficiency programs are as follows:

- The Efficient Boiler Program increased its participant numbers over both 2007 and 2008 combined, due in large part to the reinstitution of funding for retrofit applications. As such, total spending and energy savings have increased significantly, while the TRC has remained a healthy 2.0, indicating that the program benefits are double its costs. The program will accrue net energy savings of 635,497 GJ's over the life time of the measure.
- The Light Commercial ENERGY STAR® Boiler Program was officially launched in August, and had, by year's end had provided incentives for 29 boilers. The program is already logging gas savings, and has initially turned in a strong TRC of 3.3, despite initial development and communications costs. The program accrued net energy savings of 35,589 GJ's over the life time of the measure.
- The Energy Assessment Program has continued to provide guidance in energy efficiency to commercial customers and has saved an average of 299 GJ/yr per participant, translating into a total projected energy savings of 12,396 GJ's. In 2009 the program turned in a TRC result of 2.4.

The Commercial Energy Efficiency programs are described in further detail below.

4.4.3 Efficient Boiler Program

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: 2005 – December 31, 2011
TGVI: 2005 – December 31, 2011

Incentive: Refer to Appendix D for full incentive details

Program Objectives:

- Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency boilers for space heating.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate medium to large commercial customers about the advantages of high efficiency boilers and provide an incentive to facilitate the purchase of high efficiency technology.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs
- Support and prepare the way for any provincial regulation requiring increased boiler efficiency.

Background:

In operation since 2005, the Efficient Boiler Program is TGI and TGVI's flagship Commercial Energy Efficiency program aimed at reducing gas consumption associated with space heating. Fully ¾ of commercial gas consumption in British Columbia is used for space heating. The program is designed to stimulate investment in appropriately sized, energy-efficient space heating boilers that reduce natural gas usage and associated operating costs.

High efficiency boiler technology, when used as part of a properly designed heating system, generates significant annual energy savings over a comparatively long estimated measure life. In fact, high efficiency boilers represent one of the most significant sources of achievable savings for the commercial sector in British Columbia[8]. Fully 35% of such savings is attributable to high efficiency boilers. The use of boilers can be found, to varying degrees, in virtually all commercial area groups including the large and medium classes of commercial, multi-residential, and institutional customers. Typical installations include:

- Office buildings
- Apartment buildings / Stratas
- Schools / Universities
- Hospitals
- Care Homes

[8] *Terasen Gas Conservation Potential Review, Commercial Sector Report*, Marbek Resource Consultants, *April 2006*

Small commercial customers also use boilers, however this program is designed to incent larger boilers than they would typically require. Refer to the Light Commercial ENERGY STAR® Boiler program for a boiler program geared towards smaller commercial customers.

High efficiency boiler technology can be up to 95% efficient versus roughly 80% for new standard efficiency boilers. By encouraging the use of high efficiency boilers, the Efficient Boiler Program directly targets the commercial sector's most significant source of gas consumption (space heating) via one of its most widely used, and longest lasting gas burning appliances (boilers). Installing such boilers today has a lasting impact by reducing gas consumption now, while paving the way for market transformation and ultimately more stringent regulation.

Please refer to Appendix D for detailed program description.

Results:

Table 4-7 provides program highlights of the Efficient Boiler Program performance metrics for 2009. As may be seen, the performance as judged by TRC was solid, though some participation issues need to be addressed. A discussion of the results and program learnings follows the table.

Table 4-7: Efficient Boiler Program – Solid TRC performance

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	TGVI	1	13	2	892	9,869	18%	2.0
Retrofit	TGI	61	783	101	54,422	605,888	18%	2.0
	TGVI	3	39	5	2,676	29,608	18%	2.0

The program significantly increased its participation rate surpassing the combined totals of 2007 and 2008. This was largely due to the reinstitution of incentives for retrofit applications as of October 1, 2008; all but 1 participant in 2009 was a retrofit customer. Incentives for retrofit customers were excluded throughout most of 2008 due to budgetary constraints. Once the DSM budget situation improved, incentives for retrofits were once again made available.

While program participation in 2009 remains less than the program's all time high participation rate of 85 participants in 2006, it never-the-less represents a notable success in view of the generally poor prevailing economic climate and the uncertainty over the availability of incentives created by the exclusion of retrofit customers in early 2008. Furthermore, participants who complete the installation of their boiler and receive an incentive payment generally report that the incentive is better than adequate.

While the increased participation is encouraging, the lack of new construction participants as well as the low participation rate from Vancouver Island are both notable. There are several factors which have likely contributed to this situation:

1. It seems reasonable that the economic situation of late 2008 through most of 2009 played a central role in discouraging new construction projects which may have otherwise participated in the program.

2. Based on discussions with potential participants there appears to be a perception of uncertainty in the market surrounding the availability of the incentive. This seems to be largely due to program termination dates previously in place (i.e. previous program deadline, August 2009). New construction participants especially believe that the program's funding will expire before they can finish constructing their new building / facility, leading them to conclude that attempting to participate in the program is not worth their time or effort.

3. The use of fuel oil for boilers remains significant on the island. A sizeable proportion of these oil burning potential participants have limited familiarity with TGVI may thus not be aware of the company's incentive programs. This would necessarily preclude their participation in the program.

By year end the efficient boiler program had committed to pay as much as $834,800 to participants who successfully complete their boiler installation within 1 year of submitting their program application. This compares reasonably well with the highest ever annual commitment of $1,075,455 experienced in 2006, before the availability of the rebate was first eliminated and then reinstated for retrofit applications. The objective now is to build upon the current momentum and rate of participation in the program in order to maximize commercial sector gas savings.

When total program spending is compared to the avoided cost of the gas the program turns in healthy TRC results in the neighbourhood of 2.0 indicating significant total benefits result from the operation of this program. With Free Rider Rate estimated to be approximately 18%, the annual net energy savings derived from the program's participants is 57,990 GJ's. Given that the program's target customer group annually consumes more than 13,000,000 GJ's for space heating, significant room for growth remains.
For cost benefit analysis please refer to Appendix J.

<u>Planned Improvements For 2010</u>

In 2010 the Companies' will expend additional time and effort dedicated to promotions in order to raise awareness of the program and increase participation from the new construction and Vancouver Island markets.

In 2010 the Companies plan to perform an in-depth evaluation study on the program's performance at reducing gas consumption. The results of this study will serve to confirm and/or provide additional insight into the gas savings associated with the program. For additional information on the proposed evaluation study please refer to Section 5.13.3.1.

Further to the issues noted above, the program process has received generalized criticism from program participants for being too cumbersome. In addition to making the program complex and difficult for many potential participants to understand, the process also imposes a significant administrative burden on the Companies. The Companies plan to streamline the program process in 2010.

4.4.4 Light Commercial ENERGY STAR® Boiler Program

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: August, 2009 – December 31, 2011
TGVI: August, 2009 – December 31, 2011

Incentive:

Providing that the boiler is used for space heating and/or domestic water heating in combination with space heating:

- Condensing boilers: $5 per MBH[9]
- Near condensing boilers: $3 per MBH

Program Objectives:

- Reduce commercial sector gas consumption by encouraging the installation and use of high efficiency (ENERGY STAR® rated) as opposed to standard efficiency boilers for space heating.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate small to medium commercial customers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary.
- Engage the trades community and manufacturers by supporting new, energy efficient technologies.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs
- Support and prepare the way for any provincial regulation requiring increased boiler efficiency.

Background:

Launched in August of 2009, the Light Commercial ENERGY STAR® Boiler Program is TGI and TGVI's most recent offering aimed at reducing energy consumption associated with space heating. In contrast to the Efficient Boiler Program described above, this program focuses on smaller boilers. The program designed to encourage small to medium commercial customers to install energy efficient boilers by offering a cash incentive that is calculated based on the quantity, size and type of boiler.

High efficiency boiler technology, when used as part of a properly designed heating system, generates significant annual energy savings over a comparatively long estimated measure life. Refer to Section 4.4.3 for a description of the benefits and energy saving potential of high efficiency boilers. Typical facilities which see the installation of small boilers include:

- Small to medium apartment buildings

[9] Note: 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

- Small to medium office buildings
- Schools / Universities

Please refer to Appendix D for a detailed program description.

Results:

While the program's newness resulted in limited initial uptake, the TRC performance was generally encouraging.

Table 4-8 provides program highlights of the Light Commercial ENERGY STAR® Boiler Program performance metrics for 2009. A discussion of the results and program learnings follows the table.

Table 4-8: Light Commercial ENERGY STAR® Boiler Program – Encouraging start but work to be done on participation

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	TGI	11	32	20	3,197	35,589	18%	3.3

The Light Commercial ENERGY STAR® boiler program is brand new as of August of 2009. The initial response to the program has been positive from those who have successfully participated, with participants citing the program's simplicity and speed of response as positive qualities.

On the other hand program awareness remains low for the moment due to its relative newness; a situation which is quite clearly reflected in the participation numbers. The program's participants have thus far been entirely from the TGI retrofit market. Many design professionals, trades people and target customers remain unaware of the program's existence. A sustained direct promotional effort, as well as collaboration with partners in industry associations, is required to raise the program's profile among a wider audience.

For cost benefit analysis please refer to Appendix J.

Planned Improvements For 2010

2010 will see enhanced program promotions and, late in the year, a stakeholder feedback session in view of raising awareness and participation levels for the program for both TGI and TGV.

So far, the program has turned in a very healthy TRC result of 3.3 in the TGI retrofit market. It is however too early in the program lifespan to draw solid conclusions based on this number. Should the TRC remain high through 2010 despite increased spending on program promotions, consideration will be given to increasing the value of the incentive or providing an additional incentive to the installer, independent of that which is currently delivered to the customer.

4.4.5 Energy Assessment Program

Program Area: Commercial Energy Efficiency Programs

Target Market: Retrofit

Duration: TGI: 2001 – December 31, 2011
TGVI: 2001 – December 31, 2011

Incentive: A free, walkthrough energy assessment ($1200 value).

Program Objectives:

- Enable and encourage commercial customers to reduce gas consumption by identifying sources of high gas consumption within their facilities and proposing implementable measures aimed at reducing consumption.
- Educate commercial customers about gas use within their own facilities and the steps they can take to minimize consumption.
- Foster a culture of conservation among commercial sector customers (including Multi-Unit Residential Buildings (“MURBs”), institutional and manufacturing customers) by assisting them to review their energy consumption critically.
- Direct (where applicable) participants to available incentive programs including Terasen’s existing boiler programs.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs

Background:

The Energy Assessment Program has been in operation since 2001 with minor modifications over the years. This program is designed to identify inefficiencies in natural gas energy consumption and provide recommended solutions in the following sectors: condominium and apartments, food processors, greenhouses, hospitals, hotels, industry, offices, recreation centres, restaurants, schools, warehouses/offices, and wood products.

Inefficiencies are identified in participant’s facilities via an onsite walkthrough assessment by an energy efficiency consultant. The consultant then produces a report, describing the observed inefficiencies and outlining proposed energy savings measures which may be implemented to reduce gas consumption. The Companies then forward the report to the participant.

The Energy Assessment program allows the Companies to help foster a culture of conservation among commercial customers by visiting their facilities directly and helping educate them on their gas use. It is an important “first contact” which can lead to subsequent savings via the implementation of energy savings measures, with the assistance of incentive programs where applicable.

Please refer to Appendix D for a detailed program description and Section 5.13.3.3 for details on the Energy Assessment Program Evaluation.

Results:

While participation in the program declined between 2008 and 2009, the program was still able to generate gas savings.

Table 4-9 provides program highlights of the Energy Assessment Program performance metrics for 2009. The program continues to generate savings, though modifications are required in 2010. A discussion of the results and program learnings follows the table.

Table 4-9: Energy Assessment Program - Continues to generate savings

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	TGI	49	59	18	13,186	12,396	10%	2.4

Participation in this program was down from 77 participants in 2008 to 49 in 2009 and there were no participants in the program for TGVI. Despite the "free to participant" nature of the program, the economic situation of 2008 / 2009 no doubt precluded any thought of investing in energy efficiency among many organizations as business managers focused on the health of their core business. Furthermore the program has not been strenuously promoted due to issues as discussed below.
For cost benefit analysis please refer to Appendix J.
Planned Improvements For 2010

The current design of the program will undergo several changes in 2010 in view of addressing several current and future issues as well as enhancing its overall performance at reducing gas consumption per participant. More specifically some of the areas for improvement include:

1. A low rate of implementation of the recommended energy savings measures.
2. No commitment by participants to implement any of the energy savings measures.
3. The lack of a formal mechanism to track energy savings.
4. The level of detail provided is increasingly not up to what many participants require.
5. The attribution of energy savings will increasingly conflict with other programs

For a description of the proposed modifications to address these issues refer to Section 5.6.2.4. Once changes are made to the program process and administration more effort will be expended on raising the program's awareness level in the market place. This can very likely be accomplished via industry partners in addition to the Companies' own promotional efforts.

The Companies are currently engaged in a second evaluation study of the program (an initial study was completed in 2008) based on participation from July 2007 through July 2009. This study will provide additional needed insight into the program's performance and allow the Companies to confirm the data underlying the performance results presented above. Furthermore the evaluation study will provide additional insight into where the program may be modified to enhance its performance. Refer to Section 5.13.3.3 for details on the Energy Assessment Program Evaluation.

4.4.6 Summary

The Companies have a track record of promoting Commercial Energy Efficiency programs. With the additional funding provided through Commission approvals they significantly broadened their efforts in TGI and TGVI service areas, to both New Construction and Retrofit applications. The Efficient Boiler Program, the Light Commercial ENERGY STAR® Boiler Program, and the Energy Assessment Program all generally performed well in 2009, delivering value to Customers. Using the experience gleaned from these programs the Companies have identified targeted opportunities to improve effectiveness and produce further gains in 2010.

4.5 Conservation for Affordable Housing Programs

Conservation for Affordable Housing programs focuses on reducing energy consumption for low income customers, which in turn reduces their energy costs and their GHGs. Conservation for Affordable Housing is a new area of activity for the Companies. In order to recognize its importance, the Companies have created a discrete Program Area for Conservation for Affordable Housing. Although the Companies have in the past been active within working groups and task forces related to energy conservation in affordable housing, there previously weren't financial resources to contribute towards implementing programs that reduce energy consumption for residents of Affordable Housing. Now, with the additional funding provided by the Commission EEC Decision, the Companies have been able to develop programs that target this important stakeholder group.

4.5.1 2009 Programs Led to Meaningful Early Results

After receiving approval to invest in the Conservation for Affordable Housing Program Area, the Companies have spent a significant portion of 2009 on facilitation, coordination, planning, and development of programs that will be implemented in 2010 and beyond.

Despite the longer term focus of this work, the Companies also rolled out three projects that were completed in 2009. These projects were:

- The Meridian Village Project;
- The LiveSmart Carry Over Project (through the MEMPR Low Income Partnership Funding); and
- The Energy Conservation for Affordable Housing Forum.

In addition, the Companies have also continued the facilitation of the BC Working Group for Energy Efficiency for Affordable Housing and the Affordable Energy Conservation Task Force.

Table 4-10 provides a summary of the 2009 Conservation for Affordable Housing projects for the Companies. The 2009 projects were focused on retrofits and were implemented in TGI's service territory however the Energy Conservation for Affordable Housing Forum had a province-wide perspective.

Table 4-10: 2009 Conservation for Affordable Housing Projects for TGI and TGVI

Project		Description	Retrofit			
			# of Units or Participants	Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TRC
1	Meridian Village	A partnership to upgrade 124 furnaces in a MetroVancouver owned social housing complex	124	230	14,236	0.7
2	LiveSmart Carry Over	Energy efficiency retrofits in five affordable housing complexes as part of the completion of LEAP.	557	989	67,601	1.1
3	Energy Conservation for Affordable Housing Forum	A collaborative forum to strengthen energy conservation for affordable housing in BC.	83	5	N/A	N/A

Notes:
1) The final assessments have not been completed for the LiveSmart Carry Over project. Figures presented here are estimates only.
2) LiveSmart Carry Over was funded through the MEMPR Low Income Partnership Funding and therefore not included in the portfolio level TRC calculation.
3) As per DSM regulation, the TRC caluculation for all low income programs applies a deemed benefit of 130% of what the benefit would recognized as in an able-to-pay program's TRC calculation. This regulation is applied in the TRC figures shown above.

Notable achievements through the Conservation for Affordable Housing projects in 2009 are:

- In 2009 the Companies invested a total of $1.219 million in retrofits benefiting 557 units and achieved a NPV of 81,837 GJs in energy savings.
- The Meridian Village project completed furnace upgrades in 124 town house units and achieved a projected energy savings of 14,236 GJs over the lifetime of the furnaces. The program achieved a TRC of 0.7. This set of town houses received upgraded furnaces through this Meridian Village project and also received additional energy efficiency measures through the LiveSmart Carry Over project.
- The LiveSmart Carry Over project completed a variety of energy efficiency upgrades benefiting a total of 557 units. Final evaluation of this project will be completed by the end of April, 2010. Estimated savings are 67,601 GJs based on prior LiveSmart Energy Assistance Program experience which would equate to a TRC of 1.1.
- The Energy Conservation for Affordable Housing Forum attracted a total of 83 participants. The Companies were a sponsor of the Forum, contributing $5,000 to the costs of the forum, and played a central role in the coordination, administration and facilitation of the Forum.

Conservation for Affordable Housing projects are described in further detail below.

4.5.2 Meridian Village Furnace Upgrade

Program Area: Conservation for Affordable Housing Programs

Target Market: Retrofit

Duration: Furnaces installed between September 2009 and December 2009

Incentive: $1,850 per furnace

Partners: Metro Vancouver Housing Corporation ("MVHC"), LiveSmart Energy Assistance Program ("LEAP"), ecoEnergy

Program Objectives:

- Carry out an exploratory furnace upgrade project in a social housing complex to determine savings potential.
- Extend the LiveSmart Carry Over project's energy savings by upgrading 124 furnaces to high efficiency models.
- Create a partnership with MVHC, a key social housing provider.
- Gain experience and build capacity within the Conservation for Affordable Housing Program Area.

Background:

The Meridian Village furnace upgrade project was the Companies' first project in the Conservation for Affordable Housing program area. The furnace upgrade project, described in this section was an opportunity to extend the other energy savings measures that this town house complex received under the LiveSmart Carry Over project, described in the following section. Together, these two projects provided the opportunity to analyse the impact of a comprehensive energy efficiency retrofit in low income town houses. Total savings from the Meridian Village project combined with the LiveSmart Carry Over project will be compiled in April 2010. This section describes savings attributed to the furnace installation alone.

The Meridian Village project was presented to Terasen Gas as a proposal from eaga Canada Services Inc[10] on behalf of the MEMPR's LEAP program aimed at social housing providers. The Meridian Village complex, located in Port Coquitlam, is owned by MVHC.

TGI contributed $229,400 of the total $620,000 that was used to install 124 high-efficiency furnaces. Contributions are summarized in Table 4-11.

Table 4-11: Meridian Village Contributors

# of Furnaces	LEAP	ecoENERGY	Terasen Gas	MVHC
124	$80,600	$80,600	$229,400	$229,400

The townhouses in this complex are individually metered and the tenants all pay rent to the owner. This was an especially good selection for energy efficiency investments because all the furnaces were oversized at 60,000 to 70,000 BTU. By installing smaller, two-stage high efficiency furnaces (94% AFUE, 45,000 BTU), the furnaces will now be able to run at approximately 25,000 BTU the majority of the time.

Results:

Table 4-12 provides highlights of the Meridian Village Project performance metrics for 2009.

[10] eaga Canada Services Inc. a social enterprise and provider of green support services and solutions in the residential sector. eaga Canada Services Inc. focuses on tackling climate change, promoting residential energy efficiency and delivering social inclusion for low income households

Table 4-12: Meridian Village Performance Summary

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	124	229	0	1352	14,236	N/A	0.7

Note: As per DSM regulation, the TRC caluculation for all low income programs applies a deemed benefit of 130% of what the benefit would recognized as in an able-to-pay program's TRC calculation. This regulation is applied in the TRC figures shown above.

Overall, this project achieved the objective of extending the LEAP and ecoEnergy grants and extending the measures that were installed through the LiveSmart Carry Over Program. All 124 units had new high efficiency furnaces installed which resulted in NPV energy savings of 14,236 GJ's based on 10.9 GJ's savings per unit annually. The Companies incurred less than $500 in non-incentive costs largely due to MVHC taking on much of the administration of this project. The Free Rider Rate was not applicable for this project because none of these furnaces would have been upgraded if it were not for TGI's incentive.

An additional benefit of this project is that there is an improvement to quality-of-life for the residents resulting from better air quality and quieter furnaces. By installing new high efficiency furnaces that use smaller motors, the noise from the furnace operation was reduced considerably and the new standard-sized air filters can be easily and regularly replaced resulting in far more effective air filtration than the old custom-sized and improperly fitted filters, however this benefit cannot be monetized.

The resulting TRC (0.7) is lower than 1.0, which indicates that the 30% energy savings benefits allowed for low-income conservation activities may not be adequate to push programs for this sector, where the full cost of the measure rather than just the incremental cost for energy efficiency goes into the cost side of the TRC calculation. The Companies intend to hold discussions with MEMPR on this topic, to see what actions need to be taken to ensure that covering the full cost of a measure is viable from a benefit-cost perspective.

For cost benefit analysis please refer to Appendix J.

4.5.3 LiveSmart Carry Over

Program Area: Conservation for Affordable Housing Programs

Target Market: Retrofit

Duration: Installations completed between September 2009 and January 2010.

Incentive: Average incentive of $1,700 per unit

Program Objectives:

Complete the energy efficiency installations that were identified under the LEAP program.

Background:

On March 31, 2009, through the Low Income Partnership Funding agreement, MEMPR awarded TGI and TGVI a grant of $5.155 million to support and develop DSM programs for low-income individuals in British Columbia. These funds are incremental to the funds approved in the EEC Decision and the LiveSmart Carry Over project was entirely funded with the Low Income Partnership Funding (described further in Section 5.8.3.4).

In August 2009, MEMPR informed the Companies that due to fiscal restructuring occurring within government, the budget that MEMPR had allocated for the LEAP was cut by as much as $1.4 million. The LEAP was a provincial energy efficiency program for low income residents of British Columbia that was developed and administered by MEMPR. MEMPR encouraged the Companies to use the Low Income Partnership Funding to complete energy efficiency retrofits in five affordable housing complexes throughout Metro Vancouver. These retrofits would otherwise not be completed. These retrofits included items such as new high efficiency boilers, programmable thermostats, attic insulation, draft proofing and other energy savings measures. The buildings and estimated efficiency measures for this project are shown in Appendix E.

The Companies committed $965,803 to complete the energy efficiency retrofits for the five sites that were gas customers. As at the end of 2009, this contract was substantially complete.

Results:

Table 4-13 provides highlights of the LiveSmart Carry Over Project performance metrics for 2009 based on the budgeted expectations given that the final results of the project will not be known until the formal post-installation energy assessments are completed.

Table 4-13: LiveSmart Carry Over Performance Summary (Based on Budget Expectations)

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	557	947	42	7,130	67,601	N/A	1.1

Note: The cost-benefit analysis and the TRC shown above are using the same cost-benefit analysis used for all low-income EEC programs (including the deemed benefit of 130% for low-income programs) however, this program is funded through the MEMPR Low Income Partnership Funding (not the funds approved through the EEC Application).

The $947,000 in incentives is based on a budget allowance of $1,700 per unit. Estimates at the onset of the project were that the installations would average $1,667 per unit as represented by the total installation amount of $928,462 in Appendix E. The Non-Incentive amount of $42,000 includes the estimated $37,341 for assessments and an estimate of $5,000 for the Companies' administration, communication, evaluation and development. The projected NPV energy savings is 67,601 GJs which yields a TRC of 1.1.

4.5.4 Working Group and Task Force

Throughout 2009, the Companies have continued the facilitation of the BC Working Group for Energy Efficiency for Affordable Housing ("Working Group") and the Affordable Energy Conservation Task Force ("Task Force").

At the request of MEMPR, the Companies formed the Working Group in September 2008 with the objective of ensuring that lower income homes can actively participate in, and benefit from, targeted energy efficiency programs. The Working Group consists of a large and diverse group of stakeholders engaged in the topic of energy efficiency in the low income niche. Refer to Appendix E for the member organizations of this Working Group.

To meet the objective of ensuring that lower income homes are included in energy efficiency programs, work has begun on an Affordable Energy Conservation Strategy paper ("Strategy Paper"). Because the Working Group is large and geographically dispersed, a subset of the Working Group, called the Task Force has taken on the coordination role for the development of the Strategy Paper. The Task Force has also been responsible for coordinating an Affordable Energy Conservation Forum, held in March 2009. The Affordable Energy Conservation Forum is further described in the next section and the Member organizations of the Task Force are presented in Appendix E. The Strategy Paper is further described in Section 5.8.2.1.

4.5.5 Affordable Energy Conservation Forum

The Affordable Energy Conservation Forum (the "Forum") was coordinated by the Task Force and attended by many members of the Working Group. The Companies were a Sponsor for the Forum (contributing $5,000) and a primary coordinator for the event with two staff members actively involved in many aspects of facilitation, coordination and administration for the forum.

The event was successful in attracting a diverse group of 83 stakeholders (a full list of attending organizations is shown in Appendix E) to come together to discuss opportunities to deliver affordable energy conservation strategies to lower-income groups across the province.

The Forum focused on household energy efficiency and its objectives were as follows:

- To share information, strengthen relationships and build trust among stakeholders in energy efficiency, low-income service support and affordable housing sectors;
- To identify key issues, challenges and opportunities associated with integrating energy efficiency into low-income service support and affordable housing sectors;
- To identify best-practices from Low Income Energy Efficiency Programs ("LIEEPs") around the globe;
- To identify the key components of a "made in BC strategy" to address improving efficiency for low-income families; and
- To identify concrete steps to strengthen the availability of energy efficiency for low-income families with a focus on opportunities for increased coordination and/or collaboration among key stakeholders.

It was the hope of the Task Force that by establishing a baseline for dialogue, efforts at the forum could be directed toward finding affordable energy conservation solutions for lower income households in British Columbia.

Feedback from the Forum suggested that the event was effective in bringing together stakeholders to focus on energy poverty and the surrounding issues. The attendees appreciated hearing about success stories in other jurisdictions and expressed the desire to attend another similar forum in the future.

Another outcome of the Forum is the initiative of the Task Force to oversee the creation of the Strategy Paper. The Task Force has taken some steps towards creating this Strategy Paper however it is a lengthy process. This process is described further in Section 5.8.2.1.

The Task Force has had some initial discussions about hosting another Affordable Energy Conservation Forum and there is general agreement that a Forum should be held again at some point in 2010 or 2011 after the draft strategy has been written.

4.5.6 Summary

Conservation for Affordable Housing programs represent a new area of activity and focus for the Companies, one made viable through the funding approved by the Commission. And while 2009 was a year where the groundwork was being laid for this portfolio, three projects were also launched that delivered immediate results.

With this foundation in place the Companies look forward to continuing and broadening their efforts in 2010 and beyond.

4.6 Joint Initiatives

Joint Initiatives are EEC programs that involve mutually beneficial collaborations between groups such as government agencies or other utility partners. To further such Joint Initiatives programs, in July 2009 the Companies signed a Memorandum of Understanding ("MOU") with BC Hydro to facilitate increased utility collaboration on DSM. The purpose of the MOU is to drive efficiencies in program promotion, administration, and share DSM expertise to bring education and incentive programs to residents across BC. It is the Companies' intention to complete a similar MOU with FortisBC in 2010.

4.6.1 Joint Initiatives Draw on Complementary Strengths

The first Joint Initiatives the Companies will pursue are collaborations between utilities and government to develop market adoption of new technologies and energy efficiency education and outreach. Utilities have the funds and technical resources to manage pilots for new technologies to validate savings claims. As technology becomes main stream, utility incentive programs can help support education and ultimately compliance of new efficiency regulations across the supply chain. Governments can support activities such as home energy assessments, where no energy savings can be attributed to the assessments themselves, while utilizing the utility's cost-effective marketing channels to their shared constituency of consumers and trades.

The second type of Joint Initiative the Companies intend to seek out are those between utility partners. These are compelling because they can extend the market reach of a program to include all households regardless of whether or not they use electric or natural gas space and water heating. Each utility has strong brand recognition and cost-effective marketing channels. Working together creates synergies that drive program participation, energy savings and outreach while reducing administration and marketing costs.

4.6.2 Overview: 2009 Joint Initiatives

The Companies have launched Joint Initiatives that are benefiting customers and furthering EEC goals. Joint Initiatives are EEC programs that enable partnerships between utilities and government or utilities and other utilities. These partnerships enable sharing of costs, expertise and more in furthering the pursuit of EEC goals.

There were two actual Joint Initiative programs offered in 2009: EcoEnergy Home Energy Assessments in partnership with LiveSmart BC and a Tier 3 ENERGY STAR® Washer and Dryer Rebate Program in partnership with FortisBC. Table 4-14 provides a summary of the 2009 Joint Initiatives programs for TGI and TGVI.

Table 4-14: 2009 Joint Initiatives Programs for TGI and TGVI

	Program	Description	Retrofit			
			Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TRC	
					TGI	TGVI
1	EcoEnergy Home Energy Assessments (D-Visits) through LiveSmart BC	$75 Incentive to cover the partial cost of Home Energy Assessment provided by an NRCan certified Home Energy Advisor	408	0	N/A	N/A
2	Tier 3 ENERGY STAR® Washer and Dryer Rebate with Fortis BC - Six week pilot	$50 Incentive for Tier 3 washers and dryers in Fortis BC service territory	6.5	1,905	0.8	N/A

The highlights of the 2009 Joint Initiatives programs are as follows:

- EcoEnergy Home Assessment funding, provided through a partnership with LiveSmart BC, demonstrates the Companies' support for energy assessments as a critical first step in the retrofit process and "whole home" incentives. Over $400,000 in assessment funding was distributed in 2009, although no energy savings can be claimed directly as a result of this program. Rather, energy assessments are an avenue into other retrofit incentive programs that drive energy savings.

- Fortis BC Tier 3 ENERGY STAR® Washer and Dryer Rebate Pilot promoted energy and water efficient laundry practices in the Okanagan. TGI partnered with FortisBC in order to extend the reach to natural gas water heating customers. The six-week pilot was so successful that a 2010 program is under development.

These Joint Initiatives programs are described in further detail below.

4.6.2.1 EcoEnergy Home Energy Assessment (D-Visit Audit) through LiveSmart BC

Program Area: Joint Initiatives

Target Market: Retrofit

Duration: August 16, 2009 through March 31, 2010

Incentive: $75 subsidy from utility partner (based on fuel source) and $75 from MEMPR

Partners: TGI, TGVI, BC Hydro, FortisBC and MEMPR

Program Administration:

LiveSmart BC

Program Objectives:

This program intends to achieve the following:

- Provide incentives for Home Energy Assessments as the first step in improving the energy efficiency of existing building stock
- Support LiveSmart BC in the interim funding period prior to new program iteration in April, 2010
- Initiate collaborative discussions with BC Hydro, FortisBC and MEMPR

Background:

The LiveSmart BC Residential Retrofit Incentive Initiative was initially launched in May 2008 as a three year program. However with significant federal and provincial incentives, the program was oversubscribed, and provincial funding expired on August 16, 2009. At that time the Companies chose to contribute funds in support of the LiveSmart BC program, and to expand the opportunities for energy efficient retrofits for their customers.

The Companies agreed to provide a $75 subsidy for home energy assessments (D-Visit audits) to natural gas heated homes in their service territory, while the electric utilities provide the same subsidy for electrically heated homes in their service territories. MEMPR matched the utilities $75 for a total of $150 subsidy for home energy assessments. LiveSmart BC administered the program and utilities flowed subsidy payments through MEMPR to the service organizations known as Certified Energy Advisors.

Results:

In 2009, TGI supported 5,182 assessments and TGVI supported 263 for a distribution of $408,375 in subsidy funds. Total non-incentive dollars were $15,895 for TGI and $3,516 for TGVI and included $10,000 for LiveSmart BC program data for evaluation. LiveSmart BC covered program administration costs.

Due to the nature of this project in that the assessment is an evaluation step only, the Companies cannot claim energy savings for these expenditures.

Planned Improvements for 2010:

The Companies recognize the importance of home energy assessments as the first step in the energy efficient retrofits. Through the process, homeowners are made aware of retrofits that can be undertaken to improve energy efficiency, reduce energy bills and improve the comfort of their home. It is anticipated that the Companies will have provided funding for an estimated 15, 000 assessments and contributed $1.125 million from August 16, 2009 through March 31, 2010, which is the provincial fiscal year end.

4.6.2.2 FortisBC PowerSense ENERGY STAR® Tier 3 Washer Dryer Pilot

Program Area: Joint Initiatives

Target Market: Retrofit market in FortisBC territory (Okanagan)

Duration: Six Weeks Summer 2009

Incentive: $50 per washer and $50 per dryer

Partner: FortisBC

Program Administration:

FortisBC

Program Objectives:

- Capture the energy savings associated with promoting energy and water efficient laundry practices in the Okanagan.
- Determine program participation rates and logistics for a 2010 program
- Determine logistics associated with utility collaboration for appliance programs

Background:

As part of the EEC domestic hot water strategy, the Companies can provide incentives for energy and water efficient appliances. To do so most effectively the Companies will partner with BC Hydro and FortisBC in order to extend the reach of the FortisBC washer and dryer rebate program to homes with natural gas space heating and water heating.

The FortisBC washer and dryer rebate program was part of a larger pilot project to promote energy efficient laundry practices in the Okanagan. FortisBC ran a six week pilot in the early summer of 2009. In partnership with Terasen Gas, it provided $100 incentives to customers who purchased a Tier 3 ENERGY STAR® washer and dryer or $50 for a Tier 3 washer.

Tier 3 is the Consortium of Energy Efficiency's highest energy efficiency designation for the most energy and water efficient models available in the marketplace. TGI provided the Tier 3 washer and dryer incentives to any program participants who heated their water with natural gas or installed natural gas dryers.

In joining with FortisBC the Companies and their partner are able to share marketing and administration costs, and more effectively educate customers about the advantages of ENERGY STAR® appliances and conservation.

Results:

Although the pilot project was conducted during a low purchase season and with limited advertising and promotion, the program was successful, far exceeding projected goals. In total, 239 rebates were distributed with about 90 per cent of the rebates given to participants who replaced both a washer and a dryer.

Table 4-15 provides program highlights of the FortisBC Tier 3 ENERGY STAR® Washer and Dryer Rebate Program Performance metrics for 2009.

Table 4-15: FortisBC Tier 3 ENERGY STAR® Washer and Dryer Rebate Program Performance Summary

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	130	6.5	-	210	1,905	43%	0.8

Participant numbers are based on 121 washers and 9 natural gas dryers

One hundred and twenty-one washers and nine natural gas dryers were eligible for a TGI rebate. The washer count was based on participants declaring that they had natural gas water heating. The dryer count was based on an eight per cent estimate of natural gas dryers in the FortisBC service areas as determined by their 2008 REUS.

As outlined in Table 4-15, based on 2009 participants, the program is achieving annual gas savings of 210 GJ's and a projected 1,905 GJ's over the life time of the measure. For this analysis a Free Rider Rate of 43% was used. This represents the proportion of 2006 shipped appliances that are ENERGY STAR®, a number obtained from FortisBC, and BC Hydro. Since rebates are only applied to the Tier 3 portion of ENERGY STAR® models, TGI recognizes that the Free Rider Rate is over-estimated. The Companies are contacting Canadian Appliance Manufacturers Association ("CAMA") and NRCan, to obtain a more accurate estimate of the market share of Tier 3 washers and dryers as a portion of total ENERGY STAR® appliances in the market. Once known, this number will be used for the Free Rider Rate for 2010 program development.

TGI paid out $6,500 in incentive dollars and all marketing and administrative support was provided by FortisBC. The TRC was 0.8 based on the 43% Free Rider Rate that over-estimates the portion of Tier 3 appliances. The model will be revised once Tier 3 market data is obtained.

For cost benefit analysis please refer to Appendix J.

Planned Improvements for 2010:

The FortisBC Tier 3 ENERGY STAR® washer and dryer program met the objectives of promoting energy and water efficient laundry practices in the Okanagan, capturing the savings associated with the installations, and gaining the knowledge to roll out a more extensive program in 2010. Although the TRC was marginal, the Companies believe energy efficient washer programs are fundamental to the domestic hot water strategy in terms of renewing appliances and outreach on the importance of hot water conservation.

The outcome of this pilot is a learning exercise for future energy and water efficiency appliance programs for utility partner collaboration.

4.6.3 Summary

Joint Initiative programs provide numerous mutually beneficial advantages to all partners in the collaboration. In working together, utilities and government partners can extend the reach of incentives, provide cost-effective education and outreach, and generate even greater energy savings and greenhouse gas reductions. Based on 2009 successes, the Companies are expanding their Joint Initiative projects in 2010 (refer to Section 5.9).

4.7 Conservation, Education and Outreach ("CEO") Programs

Successful EEC programs depend on creating and promoting awareness, which in turn generates desire by all customers to participate in EEC activities. One important way to generate this kind of support is to foster and develop a conservation culture within British Columbia. To achieve this, the Companies have established and implemented Conservation, Education and Outreach ("CEO") initiatives. The goal is to ensure that customers are aware of and will be receptive to incentive programs when they are proposed. Additionally, CEO initiatives support the energy conservation and GHG reduction goals established by the Government of BC.

4.7.1 Supporting EEC Goals through Shared Principles

CEO initiatives have two priorities:

- Assist the community in embracing change through education of the public on energy conservation behaviours and benefits; and
- Increase participation in EEC incentive programs through education on the Companies' conservation initiatives in general.

CEO initiatives follow many of the same program principles that were put forth in the EEC Application, in particular:

- Programs will have a goal of universality; offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative;

- Where possible, programs will be uniform across the service territories of the Companies, so customers will have equal participation opportunity; and
- Programs will be multi-year so as to create a sense of funding certainty necessary to effectively implement them in the marketplace.

4.7.2 Diverse Possibilities Require Careful Screening

Given the diverse range of possible CEO activities, and the numerous regions and customer groups they can target, care must be taken when decided which initiatives to pursue. The Companies consider many factors before settling on the right initiatives. These include (but are not limited to):

- potential participant reach;
- geographically spread across TGI and TGVI service territories;
- attendance demographics and alignment of those demographics with our customers;
- media involvement, i.e. print, online, radio, in-person, cooperative advertising, or a combination thereof; and
- level of engagement with customers; activity-based vs. sponsorships and partnerships with third parties.

CEO initiatives are not individually put through the California Standards Tests at a program level. For further discussion on CEO evaluation techniques, refer to Section 5.13.3.4 and Appendix D.

4.7.3 Evolving Focus of CEO Activities Reflected in 2009 Priorities

With the EEC Decision and the new funding that accompanied it also came a new focus for CEO activities. This new focus came partly from the Commission Panel, which directed the Companies to review and refocus the CEO program.

Historically, the Companies have distributed print and online publications, exhibited at home and trade shows, and engaged in limited involvement with school programs.

And while in its EEC Application the Companies submitted a proposal developed in consultation with Wasserman + Partners Advertising, the EEC Decision suggested allocating funds away from the mass media campaign. Instead it was suggested initiatives should encompass other initiatives, including conservation education activities within the school system and affordable housing initiatives.

In 2009, the Companies expanded on initiatives which had previous proven to be successful in reaching a large number of consumers. In addition, the Companies also launched a number of new initiatives in Q4. Existing and new CEO initiatives have used limited mass media channels, and instead increased the engagement level with the public in order to achieve the CEO objectives.

As many of these initiatives began in Q4 and are continuing into 2010, much of evaluation for the CEO initiatives will be conducted in 2010 and are further described in Section 5.10. Table 4-16 provides a summary of the 2009 CEO initiatives and costs for TGI and TGVI.

Table 4-16: 2009 CEO Initiatives and Costs

	Initiatives	Description	Expenditures ($000s) TGI	TGVI	Total Expenditure ($000s)
1	Print and Online Publications	Energy conservation education promoted through bill inserts, newspaper and magazine ads, trade show guides, newsletters, directories, and terasengas.com.	**209**	**12**	**221**
2	Trade Shows and Events	Participated in residential home shows and commercial trade shows to reach customers and educate on energy efficiency rebate programs.	**76**	**26**	**102**
3	Students and Schools Outreach: Destination Conservation	K-12 program educating students and teachers about energy conservation and efficiency and providing them with cirricula and support materials.			
4	Students and Schools Outreach: Beyond Recycling	K-7 program educating students and teachers about energy conservation in West and East Kootenays			
5	Students and Schools Outreach: BC Green Games	K-12 competition for students to submit digital entries of their environmental projects.			
6	Students and Schools Outreach: School Assembly Presentations	K-7 school assembly presentations on energy conservation through interactive competitions.	**77**	**40**	**117**
7	Energy Champion Program	Educate children and youth about energy conservation behaviour changes, using tlregional sports team events..	**123**	**3**	**126**
8	Team Terasen Outreach	Outreach group delivering the Company's EEC message by connecting with customers at community events and festivals.	**45**	**0**	**45**
Total - Actual			**530**	**81**	**611**

The activities that make up the CEO initiatives are designed to create and promote awareness and educate the public. Increased awareness and education results in higher levels of participation in EEC activities and programs. The CEO activities for 2009 are set out and described in further detail below.

4.7.4 Print and Online Publications

Print and online publications are a cost-effective communications channel for delivery of information when compared to other communication channels such as television and mass media. The goal of the CEO print and online publications is to continually inform customers about various low-cost and no-cost upgrades they can perform at home to reduce their energy consumption. These publications also provide tips and hints to help guide consumers in their decision making when purchasing energy efficient equipment. Print publications target customers that are already contemplating home renovations or equipment upgrades.

In 2009, the Companies continued to provide information through: customer bill inserts, magazine advertisements, appliance information sheets, industry association newsletters and directories, and the corporate website, www.terasengas.com. Conservation messages focus on seasonal actions that coincide with customers' usage of natural gas, for example water heating actions in the summer and space heating in the fall and winter. The core conservation educational print publication is the "Hot Tips" booklet. This booklet contains a number of energy saving tips for homeowners. It is distributed to customers who participate in EEC activities and programs to identify further opportunities for energy efficiency. The Hot Tips booklet is distributed at all trade shows and events.

4.7.5 Trade Shows and Events

Trade show and event activities remain an effective way to reach customers with general low-cost and no-cost energy saving information. Trade shows and events create opportunities for dialogue with customers to answer general energy related questions, the Companies' incentive programs and promote participation.

The Companies have exhibited in trade shows since 2006, and continued trade show activity in 2009 by participating in residential home shows, and Canadian Home Builders' Association ("CHBA") events. The CHBA branches represent the British Columbia residential housing industry. The CHBA branches are made up of members within the residential construction industry who liaise with local governments, promote the interests of housing consumers, and work to ensure a fair market place.

The majority of the attendees to these trade shows are homeowners specifically looking for home renovation and equipment upgrade information. Depending on the show's size, total attendance can range from 5,000 to 45,000. In addition, the Companies have display exhibits at industry specific shows targeting business customers. Based on the increasing number of customer inquiries regarding conservation and equipment retrofits, the Companies believe that participation in trade shows is an essential initiative in educating customers about EEC programs. For a complete list of 2009 trade shows and events, please refer to Appendix D.

4.7.6 Students and Schools Outreach

While limited EEC funds limited the scope of activity, the Companies have historically supported conservation education in schools. Since receiving the EEC Decision, the Companies have increased their student and schools outreach through a variety of initiatives.

The goal of the Companies' school outreach activities is to educate students on natural gas and how gas fits into the province's energy picture. Education also explores energy conservation. By reaching out to students, the Companies are instilling conservation knowledge early. The goal is to foster a "culture of conservation".

As school programs generally run over the September to June time period, the initiatives described below are continuing into 2010 and will undergo an evaluation after they have been completed.

4.7.6.1 Destination Conservation

TGI has been supporting the Pacific Resource Conservation Society's Destination Conservation ("DC") program since the 1999-2000 school year. DC is a three-year K-12 school program involving students, teachers and school facilities management staff. In 2009, the DC program was made available for the TGVI service territory. The main purpose of the program is to educate schools on ways to reduce consumption of energy, waste and water, and motivate them to participate in energy conservation projects.

The Companies' support for DC is with a goal to bring in at least two additional school districts each year that would not have participated if the funding had not been available. With a multi-year school program in place, this provides stability in planning for the teacher and students to be able to build upon previous lessons and projects. Please refer to Appendix D for further detail on the Companies' funding and summary of the school districts that are currently participating in the DC program.

4.7.6.2 Beyond Recycling Program

The Beyond Recycling program is a new program in 2009, delivered by the Wildsight organization. Wildsight is a non-profit organization that focuses on biodiversity and healthy human communities in the Columbia region. Beyond Recycling provides students with an understanding of the connection between consumption patterns and environmental impacts.

The program contains lessons in reducing waste and greenhouse gas emissions and the role of natural gas in BC. The Companies co-fund the program with Environment Canada's EcoAction Community Funding Program, and FortisBC. The funding of this program is to ensure conservation outreach to schools that may not otherwise have been able to participate. See Appendix D for additional details on the Beyond Recycling program.

4.7.6.3 BC Green Games

BC Green Games, which first started in the 2008-2009 school year, is a province-wide competition hosted by Science World. This is a new initiative for the Companies, who are co-sponsoring with BC Hydro, and participate in both the Advisory Committee and Judging Panel. By co-sponsoring this initiative, the Companies are able to introduce the concept of natural gas as a resource and the need for energy conservation into the students' environmental projects.

The Green Games competition requires student teams to submit digital entries on their environmental projects for prizes. BC Green Games ties into other initiatives such as Destination Conservation and Beyond Recycling by providing a means to showcase team projects that were developed in those programs. Where Destination Conservation and Beyond Recycling successes would have been limited to the school or community, BC Green Games allows students to learn about initiatives in other schools, learn from their peers, and build on their existing or new projects for the next year. See Appendix D for additional details on BC Green Games.

4.7.6.4 School Assembly Presentations

By reaching into schools in partnership with athletes the Companies have taken meaningful actions in their efforts to foster a "culture of conservation." One such new initiative that the Companies supported in 2009 was a partnership with the BC Lions, where players from the team delivered interactive and informative presentations to assemblies at 50 elementary schools throughout BC.

The Companies co-funded the program along with LiveSmart BC, including both the Ministry of Education and the Ministry of the Environment, and Plutonic Power. The goal of this initiative was to launch a program that interacted with students and brought conservation education directly into the schools.

The assembly presentation featured B.C. Lions players talking to students about environmental responsibility and then engaging with them in competitive games that focused on recycling, water, and energy conservation. After the assembly, the players visited a Grade 5 class for a more in-depth lesson. This initiative was successful in that it reached at least 15,000 students. Partnering with the BC Lions has been beneficial as the players act as role models in promoting energy conservation and teamwork. Refer to Appendix D for a list of the schools that received the presentations.

4.7.6.5 Energy Champion Program

The Energy Champion program is a new initiative that the Companies developed and executed through local sports teams such as the BC Lions, Vancouver Giants, and the BC Hockey League. The goal of this program is to educate children and youth on energy conservation behaviour in a fun and rewarding manner.

These partnerships enable the Companies to leverage traditional media channels, such as radio, as well as the sports teams' online and social media channels. Because these channels are well developed in the market and reach out to a large number of the teams' fans, they provide the Companies with easy and immediate access to important stakeholders.

Moreover, partnering with regional sports clubs is an excellent way to reach out to families. Many families have children participating on sports teams and this program contributes to building positive associations with sports. Sports fans are generally loyal and highly engaged with teams they identify with. Often, engaging through team websites and newsletters allows the Companies targeted access to a specific audience through a low-cost communication channel.

The Energy Champion program is designed to engage both the youth audience and their parents. As the sports clubs' season runs from approximately September to April, the Energy Champion program will be continuing into 2010 and will undergo an evaluation after it has been completed. Please refer to Appendix D for detailed program description.

4.7.7 Team Terasen Outreach

The Team Terasen Outreach group ("Team Terasen") is similar to the BC Hydro Community Outreach team. First launched in 2007, it is a grassroots channel for delivering the Companies' EEC messages. It connects the Companies' customers through educational and interactive activities.

These events and activities generally attract a large audience as most of the events are free for the public to attend and reside in local communities. These activities have proven to be a cost-effective method of reaching out to the public that would normally be absent from home shows. By attending local community events, this allows customers to put a "face" to Terasen and learn about energy conservation. These opportunities contribute to the Companies' goal of building a culture of conservation.

In 2009, the goal of the Team Terasen was to expand into the Fraser Valley area and generally into corporate offices Refer to Appendix D for a complete list of events attended in 2009.

4.7.8 Summary

The CEO initiatives follow many of the same Program Principles that were put forth in the EEC Application. They are programs that are designed to be accessible to all customers, uniformly across TGI and TGVI territories, and are multi-year programs to ensure effective implementation and stability in the marketplace. The objective of CEO initiatives is to support the development of a conservation culture within British Columbia.

The initiatives described throughout this section will continue to promote and educate the public on energy conservation behaviours. The result will be fostering a "culture of conservation", which will benefit communities, increase participation in EEC incentive programs, and ultimately support shared goals of the Companies and province.

4.8 Enabling Activities

Enabling Activities are activities that support the Companies' EEC program development and delivery. They play a very important role within EEC in that they provide resources common to the support and ultimately, the delivery of all Program area activities.

4.8.1 Four Key Areas of Focus In 2009

In 2009, Enabling Activities fall into four major categories:

Research and Evaluation (Section 4.8.2): These include two general areas of activity: market research and program evaluation. Market research provides invaluable information used for planning and implementing effective programs and program evaluation helps to measure the effectiveness of a particular program and/or initiative. The highlights of the 2009 Research and Evaluation activities are as follows:

- Delivery of the 2008 REUS results, which includes data that assists in program planning and development, marketing, education and communication activities.

- Participation in the second wave of a study that focuses on North Americans' attitudes, perceptions and behaviours around sustainability and social responsibility as well as the impacts they have on lifestyle choices, brand relationships and purchase decisions.

- Completion of the Residential Retrofit Market Evaluation for Terasen Gas, to evaluate the residential retrofit market and audit the LiveSmart BC Residential Retrofit Incentive program to determine the viability of the LiveSmart BC brand and identify opportunities and threats in regarding its continued use.

- Completion of the second phase of the ENERGY STAR® Heating System Upgrade Evaluation that provides the Companies with estimates of program impact on natural gas sales and carbon dioxide emissions, in addition to determining the status of market transformation for high efficiency furnaces.

Efficiency Partners Program (Section 4.8.3): Formed to consolidate and enhance existing service and supplier relationships, to provide a delivery pathway for all EEC programs to customers. The EEC Decision ruling did not approve the discrete Trade Relations budget area put forward for these supporting activities as it was identified as a duplication of commercial and residential program delivery expenditure. The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the overall EEC TRC. The EEC Stakeholder Group has not identified any objection to this approach. These various industry groups, including manufactures, service contractors, distributors and retailers, influence end use Residential and Commercial customers who make energy efficiency decisions. Customers will defer to advice received from these groups. The activity highlights of the Efficiency Partners Program for 2009 are as follows:

- Evaluation of the existing Qualified Dealer program and development of a new Contractor program for B-Ticket Contracting companies.

- Establish energy efficiency equipment manufacturer and supplier contacts.

- Identify all contractor stakeholder groups.

- Development of the new Contractor program with a rebrand and expansion of the scope of the existing TGVI Qualified Dealer program. Expansion of service areas to include the TGI Lower Mainland and Interior.

- TGVI surveys and Contractor focus groups were completed where EEC gained valuable information useful in developing the new support programs.

Codes and Standards (Section 4.8.4): Utilities play an important role in energy efficiency market transformation through support for the development of Codes and Standards. Government and regulating bodies are constantly seeking the participation and input of stakeholder groups, such as utilities, which have a unique understanding of energy supply and customer demand cycles. The Province's Energy Plan target levels and the timing of implementation are directly connected to effective market transformation in all EEC Program Areas. Utilities also play a role in keeping industry informed of developing codes and in alerting stakeholder groups of any unintended consequences that may arise out of proposed codes and standards. The activity highlights for the Codes and Standards for 2009 are as follows:

- Codes and Standards that have relevance to EEC program development were benchmarked.

- A focus on the development of the upcoming new construction building code with an EnerGuide 80 efficiency target. Involvement at this time is crucial as very aggressive code changes with poor direction could have a negative effect on EEC programs and the market transformation process.

Pilot Programs (4.8.5): These test the effectiveness of a particular measure in the EEC market place. Pilots are utilised to verify potential savings and identify potential market transformation barriers in order to effectively design and implement EEC programs. They are also theoretically (and practically) known to improve the success of market adoption of a particular technology; allowing for a select group of customers to test new technologies prior to widespread delivery to the market place. The highlights for the 2009 Pilot Programs are as follows:

- The Okanagan Spray N' Save Pilot Program was developed and launched. Its primary goal to verify potential energy savings for kitchen spray valves used in the commercial kitchen applications.

- The TGVI Furnace Servicing Pilot Program was implemented with the objective of promoting the benefits of annual furnace servicing. Increasing awareness of energy efficiency appliances. Customers are rewarded for their service with a $25 gift card to a local food store chain.

Table 4-17 below provides an overview of the 2009 expenditures for the Enabling Activities.

Table 4-17: 2009 Enabling Activities – Expenditures

Program		Description	Expenditure ($000s)	
			TGI	TGVI
1	Research and Evaluation*	Market Research and Evaluation for potential EEC programs	12	3
2	Efficiency Partners Program	Delivering EEC programs through B-Ticket Contract Companies	7	20
3	Codes and Standards	Codes and Standards related to EEC Program areas	10	3
4	Pilot Programs	Verify potential savings and identify market barriers	28	224**

*Note that $15K ($12K for TGI and $3K for TGVI) shown in this table reflects the actual amount spent on R&E Activities in 2009; the variance is expained in table 4-18.

**Note that $224,000 is based on $199,023 paid out in 2009 and $26,000 that will be paid in 2010.

Further information on each of the four areas of the 2009 Enabling Activities is listed below.

4.8.2 Research and Evaluation

In general, the Companies engage in two general areas of activity in this area: market research and program evaluation. Both are important – market research because it provides invaluable information used for planning and implementing effective programs; and program evaluation because it helps to measure the effectiveness of a particular program and/or initiative. This section provides a high level description of the research and evaluation activities EEC undertook in 2009; further details for these studies are provided in Appendix D.

4.8.2.1 Overview: Research

Market research is defined as systematic, objective collection and analysis of data about a particular target market, competition, and/or environment. It always incorporates some form of data collection; sometimes this means primary research (collected directly from a respondent), in other cases it means secondary research (collected from additional sources including related literature, the Internet and media sources).

It is important to conduct both secondary and primary research because together they allow the researchers to gain valuable insight about energy efficiency and conservation. Armed with this knowledge they are better able to develop, implement and evaluate programs and activities.

4.8.2.2 Overview: Evaluation

Evaluation of EEC programs and activities allows EEC staff to measure the effectiveness of the programs. Historically, the Companies have conducted evaluation studies for DSM programs since the late 1990s.

In general, program evaluations are designed in two stages. During the program design phase, the program evaluation concept is determined. The primary purpose of this is to understand the data that will be required for the evaluation, and to determine how much of this can be collected during program operation, for example, as part of the incentive application. By doing this development prior to program launch, better quality data can be collected and at a lower cost than if evaluation design is left until the time for the evaluation.

Once the program has operated for a sufficient period of time, an impact evaluation can be undertaken, and the detailed program evaluation plan will be developed. In the past, the evaluations conducted on behalf of the Companies have been conducted by outside consultants who have been selected based on relevant experience and cost. Once selected, the consultant then develops the detailed evaluation plan for review and discussion with the Companies. When the plan has been approved, the consultant typically begins the field research begins which includes but not limited to field research (i.e. with participants and with the relevant trade allies), billing analysis, sub metering etc. Once field research is completed, the study moves into the analysis phase that results into a final report and develops a report.

4.8.2.3 Research and Evaluation Studies Conducted In 2009

As enabling activities, these expenditures are included in the overall portfolio-level EEC TRC test results. Each of the research and evaluation activities the Companies undertook in 2009 are further discussed below; the costs associated with these activities are shown in the table below:

Table 4-18: 2009 Research and Evaluation Studies

	Study	Description	Expenditure ($000s)	Expenditure ($000s) 2009	Variance
1	REUS	Usage of natural gas in the residential sector	20	0	Paid in 2008
2	Residential Retrofit Market Evaluation	Assess LiveSmart BC brand awareness among BC residents	18	0	Paid in 2010
3	ENERGY STAR® Heating System Upgrade Evaluation	Verify energy savings for furninces and boilers	9	0	Paid in 2008
4	SHIFT Report	Attitudes towards sustainability	30	15	$15,000 paid in 2009 $15,000 paid in 2010
	Total		**77**	**15**	

In 2009, the Companies undertook a number of EEC research and evaluation activities, including REUS, Sustainability and Social Responsibility Attitudes Study ("SHIFT") Report, Residential Retrofit Market Evaluation for Terasen Gas, and ENERGY STAR® Heating System Upgrade Evaluation. The details of each study and summary of results are provided below.

4.8.2.4 Residential End USE Study ("REUS")

The primary aim of the 2008 REUS was to understand how natural gas was being used by TGI and TGVI's existing residential customers – and to compare the results with those from the earlier studies (described in Appendix D).

The findings suggest that declines in weather- normalized use rates (i.e. gas consumption per household) have been experienced in four of the five TGI's regions between 1999 and 2008. Overall, the Companies' use rates are down 15.5% since 2002, and 20.7% since 1999. Whistler was the only region experiencing an increase in its residential use rate since 2002 (+6.4%).

The 2008 REUS report is a resource for the Companies' management and staff to determine attributes regarding the existing customer base. It summarizes the survey data and identifies key trends specifically to meet the needs of forecasting, program planning, marketing, and communication functions within the Company. The EEC team uses the findings for program planning and development, marketing, education and communication activities. Further details are described in Appendix D.

4.8.2.5 Sustainability & Social Responsibility Attitudes Study Report ("SHIFT Report")

In the early 2009, the Companies had an opportunity to be involved in the second wave of an annual market research study that focuses on North Americans' attitudes, perceptions and behaviours around sustainability and social responsibility as well as the impacts they have on lifestyle choices, brand relationships and purchase decisions.

The Companies participated in the study with a goal to gain an insight on what drives consumers to make sustainable and socially responsible choices as it relates to energy efficiency, insight into the sustainability profile of people who had already made sustainable and socially responsible choices related to home energy, and their behavioural profile. The study found that 69% of Canadians say they have already made sustainable and socially responsible choices related to home energy; lighting and home heating are the top two areas they say they have made such choices and purchase decisions.

The findings will be used as a reference guide to develop products & programs, select strategic affiliations and develop positioning and marketing communications strategies. Further details are described in Appendix D.

4.8.2.6 Residential Retrofit Market Evaluation for Terasen Gas

In November 2009, Terasen Gas commissioned Angus Reid Strategies to evaluate awareness levels among members of the general population regarding energy efficiency programs, rebates and incentives. The study was designed to provide insight into the various factors that motivate homeowners to participate in incentive programs, as well as to determine awareness of existing programs and brands.

The findings demonstrate that respondents are interested in reducing their energy bills and choose to participate in incentive programs for financial reasons, especially to save money over time. Reducing waste and protecting the environment were also identified as important reasons to participate in energy efficiency programs. In addition to incentive amounts, administrative processes can also influence participation rates, and respondents stated that program simplicity and centralized information were key factors in deciding whether or not to participate in an incentive program. Brands evaluated in the survey included Terasen Gas, BC Hydro Power Smart, Fortis BC PowerSense, LiveSmart BC, ENERGY STAR®, EnerChoice, among others.

The findings from this study will be used by the Companies and the utility partners to determine the strategy for the joint residential retrofit program described in Section 4.6. The findings will also act to guide program planning and development, marketing, education and communication activities. Further details are described in Appendix D.

4.8.2.7 ENERGY STAR® Heating System Upgrade Evaluation

In order to evaluate the effectiveness of the 2005-2007 ENERGY STAR® Heating System Upgrade Program, the Companies commissioned Habart in summer 2007. The goal of the study was to assess the effectiveness and participant satisfaction of the program through field research and verify energy savings through billing analysis.

The report consisted of two phases. The completed report of phase one of this study and the costs associated with it was filed in the response to EEC Application BCUC IR 1.71.2.1 on July 11, 2008. The primary objective of the second phase of the evaluation was to update estimates of program energy and demand savings using a comparison of weather-normalized billing histories for participants, and a comparative sample of non-participants (billing analysis).

The study found that 57% of participants in the Companies program credited it for influencing their decision to purchase a high efficiency furnace. Furthermore, based on net 9.6 GJ per annum savings per high efficiency furnace, the program generated 78.8 terajoules ("TJs") in annual savings for the first 2.3 years and 47.4 TJs of annual savings in subsequent years. The findings were used for program development and for estimating energy savings achieved through the subsequent waves of the programs. For further details, please refer to Appendix D.

4.8.3 Efficiency Partners Program

End use Commercial and Residential gas customers rely heavily on the opinions of industry specialists when making efficiency decisions. The Efficiency Partners program area was formed in the latter part of 2009, to enhance existing supporting activities and identify new activity areas to meet the needs of delivering new EEC programs.

4.8.3.1 Overview

The Efficiency Partners program areas are aimed at building relationships with various industry groups. These groups include: manufacturers, service contractors, distributors retailers, and companies that influence residential/commercial end use customers who are making energy efficiency decisions. As customers rely on the advice of these groups, an ongoing relationship with these efficiency partners is vital to effective EEC program delivery.

4.8.3.2 2009 Focus and Expenditures

For 2009 the program focus was on evaluating and developing the new Contractor program and maintaining the Qualified Dealer Co-op advertising activities for the TGVI service area. Table 4-19 identifies areas of operation and annual expenditures.

Table 4-19: 2009 Efficiency Partners Expenditures

Contractor Program	Expenditures ($000s)				
	Q1	Q2	Q3	Q4	Total
TGI	0	1	2	4	7
TGVI	0	0	2	4	6
TGVI Co-op Advertising	3	3	3	4	14

The 2009 Efficiency Partners Contractor program detail are further discussed in Appendix D of this Report.

4.8.4 Codes and Standards

With the expansion of the Companies EEC activities, efforts were made to identify current codes and standards that have relevance to EEC program development and implementation. The BC Energy Plan maps out emission and energy reduction targets levels. These aggressive target levels have a direct effect EEC programs in almost every area.

4.8.4.1 Potentially Significant Impact of Codes and Standards

One of the outcomes of market transformation is regulation through Codes and Standards. EEC programs are directly affected by these regulations. Prematurely aggressive efficiency target levels with a lack of equipment and service history to meet these performance levels could slow down or stop market transformation. This could result in substantial load shift to other energy sources, disturbing the energy supply balance thus effecting energy delivery rates to all customers.

Utilities also play a role in keeping industry informed of developing regulations and alerting the stakeholders groups of any unintended consequences that may arise out of proposed codes and standards.

There are a number of product areas where regulations are connected to EEC programs:

- Commercial Water Heaters and Boilers
- Residential Furnace
- BC Building Code
- Residential Boiler
- Hearth Products
- Residential Domestic Hot Water Heater
- EnerGuide 80 Building Code For 2010
- Towards Net Zero Buildings in BC for 2020

EEC department members work on key market committees that have the greatest effect on program areas. The Companies' Technical Sales and Support ("TSS") department maintains working relationships with various additional committees. A staff member of Technical Sales is assigned to the EEC group to provide a conduit to the services and knowledge of the Companies' TSS department and a point of liaison with TSS on regulation and codes and standards.

4.8.4.2 Focused on Regulatory Involvement to Promote EEC Goals

Keeping current is important, however the Companies' participation in the development phase of regulation allows for more effective EEC program delivery and successful DSM market transformation. This requires various levels of involvement. Codes and Standards are established at a Federal level and adopted with or without changes at the Provincial level. The BC Provincial government has a history of early adoption of regulations with aggressive energy and emission reduction levels. This puts BC industry stakeholder groups in the market transformation hot seat.

In the highlights section of Codes and Standards, the Utilities level of regulatory involvement is indicated by one of three involvement classifications:

- Monitoring: For most applications the Companies *Monitor* the status of Codes and Standards through update reviews and representation on the Canadian Standards Association steering committee. This gives us the ability to keep current and provide input to potential changes to <u>all</u> CSA codes. This is the lowest level of involvement.

- Stakeholder Engagement: For select Provincial Code adoption committees, the Companies participate at a *Stakeholder* level, actively attending meetings with other key market stakeholders and providing guidance to the end adoption recommendations.

- Developing Regulations: In support of Government's Energy and Climate Change objectives, the Companies take a *Development* role with potential Provincial regulations that potentially have a direct effect on EEC program market development. This may or may not involve financial support to provide computer modelling to identify the differences in Natural Gas use. This is the highest level of Involvement.

The sections that follow are the highlights of codes and standards as they apply to EEC program areas and are presented in order of the Companies Involvement Level.

4.8.4.3 Standards and Company Involvement: Monitoring Level

What follows is a list of codes and standards where the Companies monitor status and remains abreast of potential changing CSA codes.

<u>Commercial Water Heater and Boiler Regulations</u>

There are no current proposals for regulation changes to commercial water heater or commercial boiler standards. However these products have been discussed in 2009, and discussions will continue in 2010. There are a number of different codes and regulations here defined by BTU cut points and domestic potable vs. heat usage application. We monitor these codes and ongoing changes.

<u>Residential Furnace Regulations</u>

For new construction, gas furnaces manufactured on or after January 1st 2008, must have minimum fuel efficiency level of 90% AFUE.

For existing dwelling retrofits, gas furnaces manufactured on or after December 31st, 2009 must have a minimum fuel efficiency level of 90% AFUE. As in stock furnaces manufactured before the cutoff date can still be retailed, customers still have a mid-efficiency choice. The Utilities had a stakeholder evolvement with the adoption of this standard and now will monitor any changes that may come out of implementation.

<u>New Construction BC Building Codes</u>

The following Federal regulation changes came into effect on September 2008 as the first steps to reduce greenhouse gas emissions related to buildings and construction.

- R20 Insulation for frame walls Natural Gas heated buildings for areas of 3500 deg days or less
- Increase attic space insulation from RSI 7.7 (R43.72) to RSI 9.0 (R 51.1) in the colder areas of BC (4500 deg days and more)

- Achievement of an EnerGuide System rating of 77 as an acceptable alternative to compliance with insulation table for residential buildings
- Non residential building Part 9 buildings must now provide thermal insulation in wall, roof and suspended floor assemblies. The amount of insulation is derived from ASHRAE 90.1-2004
- All other buildings (primarily Part 3) must comply with ASHRAE 901-2004 standard

The Companies worked on a stakeholder level with the Provincial adoption of this code and monitors implementation.

4.8.4.4 Standards and Company Involvement: Stakeholder Level

Below is a list of codes and standards where the Companies participate with other industry stakeholders and provide input as regulations are developed.

Residential Boiler Regulations (Still in proposal stage)

Effective September 2010, gas hot water boilers are to have a minimum 82% AFUE and no constant burning pilot light.

Table 4-20 outlines NRCan's proposed standards for residential boilers:

Table 4-20: Proposed Residential Boiler Regulations

Boiler Type Minimum	Effective Date September 1, 2010	Effective Date September 1, 2012
Gas Hot Water	82% AFUE No constant burning pilot	Automatic means for adjusting water temperature
Gas Hot Water equipped with tank-less domestic water heating coils	82% AFUE No constant burning pilot	-
Gas Steam	80% AFUE No constant burning pilot	-
Oil Hot Water	84% AFUE No constant burning pilot	Automatic means for adjusting water temperature
Oil Hot Water equipped with tankless domestic water heating coils	84% AFUE	-
Oil Steam	82% AFUE	-
Electric Hot water	-	Automatic means for adjusting water temperature

The Residential boiler code has remained unchanged since 1998, and the new version is due to come out in 2010, with no major changes expected. We will review the code at a monitoring level.

Hearth Product Regulations

There is currently no regulation for minimum efficiency of Hearth Products. However, Natural Resources Canada requires that fireplace should have Fireplace Efficiency ("FE") rating label. Models currently available range from 30% to 70% AFUE.

The CSA has established an appliance testing procedure for manufacturers to establish efficiency ratings. The Companies were involved with industry stakeholders to develop the EnerChoice top tier labelling system to help customers identify efficiency levels.

4.8.4.5 Standards and Company Involvement: Developing Level

The following is a list of codes and standards where the Companies are involving in developing regulation:

Residential Domestic Hot Water Heater Regulations

Water heating represents about 20% of household energy use in Canada. Water heating will account for an ever increasing share of energy use as envelope construction, appliances and HVAC continue to improve in efficiency while conventional water heating equipment has changed little. A proposed 5 year plan to regulation changes are listed in Table 4-21.

Table 4-21: Proposed Domestic Hot Water Tank Regulations

Type	Minimum Efficiency	Effective Date
Gas Storage -151L water heater	0.62 EF	September 1, 2010
Gas Storage -189L water heater	0.61 EF	September 1, 2010
Gas Storage Water Heater	0.67 EF	2011 (Proposed)
Gas Storage Water Heater	0.80 EF	2014 (Proposed)
For the first two items, EF rating is based on a formula EF= 0.70 – (0.0005*V)		
V=volume of storage water tanks in litres.		
Storage tank volumes of 151 litres and 189 litres are typical residential heater sizes.		

The first phase of this regulation begins September 1st 2010, but still allows for the sale of any less efficient water heaters manufactured prior to this date. Customers will still have a choice until existing inventories are exhausted. This first tier of change should not provide adverse market problems, however manufacturers have indicated that they have concerns with the second and third tiers of the proposed regulation. Utilities are working to try to bring stakeholders together to determine the appropriate market transformation plan.

The Companies' proposal for the attribution of savings from the introduction of the 2014 water heater regulations is discussed in Section 7 of this report.

EnerGuide 80 New Construction Building Code For 2010

The Provincial Government has announced that they are working toward the implementation of EnerGuide 80 ratings for the BC Building Code to take effect in late 2010. The current rating of 77 and the new 80 rating are stepping stones toward a Net zero level set for 2020. The Province of British Columbia is updating the energy efficiency requirements in Part 10 of the BC Building Code for residential buildings. Along with Industry stakeholders a study was started in 2009 to determine potential combinations of overall building envelope thermal requirements, air tightness, and equipment efficiency which will meet EnerGuide 80.

The Companies are involved at a partner level with BC Hydro and other industry stakeholders in the steps involved with code assessment and development. A number of base cases were modelled utilising the NRCan Hot 2000 program, using the following variations:

- Various archetypes of detached home, row home

- Primary space heating system: electric, natural gas (water heating is assumed to match)
- Climate Zones in BC: Southern Coastal (<4000 DD), Southern Interior (4000 – 5000 DD), Northern Interior (>5000 DD)

The modelling study will be completed by the end of January 2010. A stakeholder committee will be struck to develop the guidelines for changes to the BC building code biased on the results of the modelling study and input from the representing groups.

To date it is clear that a review of the existing D audit process will be required as more weight is placed on the resulting EnerGuide rating of the home. Our participation is vital as decisions here will affect Companies EEC programs.

Towards Net Zero Buildings in BC for 2020 (Future Code)

The Province of BC has announced that they are moving toward a net zero energy or net zero energy capable (Passive House standard) construction code by 2020. Terasen Gas participates in both the EnerGuide 80 and Net Zero committees as the first leads to the second as and end goal.

A net zero home at a minimum, supplies to the power grid, an amount equal to the total amount of energy consumed. Combining the amount of energy (electricity and if applicable natural gas) utilised to operate a home and provide an equal amount of solar generated energy back to the grid when possible. A Passive house generates and stores all it requires without connection to any utility supply. Net zero energy capable construction code by 2020 will require the development of an implementation road map to identify the barriers and develop solutions with all stakeholder groups.

We are participating at a stakeholder level at this point in development. The group is identifying barriers at this point and listed below are some of the questions we will need to answer:

- What will be the role of the utilities be when net zero and passive houses appear in numbers?
- What are the ramifications to the Gas Industry of pursuing net zero energy buildings as opposed to net zero *emissions* buildings as a target for building codes?
- With EnerGuide 80 and Net Zero what is the best measuring stick for energy performance in buildings? For the residential sector? For the commercial/institutional sectors? How should we set our targets and how do we know in the future if we're achieving them?
- What actions need to be undertaken with building the trades/professions/industries and their associations to rapidly facilitate net zero/high energy performance in new construction and retrofit work when we as a province may be ahead of the regulatory requirement nationally?
- What is the role of occupant energy efficiency education and behaviour and who shares responsibility for ongoing, impactful occupant education?

4.8.5 Pilot Programs

As previously outlined, Pilot Programs test the effectiveness of a particular measure in the EEC market place. Pilots are utilised to verify potential savings and identify potential market transformation barriers in order to effectively design and implement larger-scale EEC programs. In 2009, EEC conducted the following two Pilot Programs; the details and the costs associated with these Pilot Programs are provided below.

- TGI developed and launched the Okanagan Spray N' Save Pilot program to investigate and confirm both the potential energy savings as well as the market acceptance of low flow pre-rinse spray valves used in commercial kitchens.

- The EEC team developed the TGVI Furnace Servicing Pilot program, "Give Your Furnace Some TLC," to promote the benefits of annual furnace servicing.

Table 4-22: 2009 Pilot Program - Expenditure

	Pilot Program	Description	Expenditure ($000s)
1	Okanagan Spray N' Save Pilot Program	Verify energy savings for commercial kitchen spray valves	28
2	TGVI Servicing Pilot Program	Promote the benefits of annual furnace servicing	199

4.8.5.1 Okanagan Spray N' Save Pilot

Program Area: Commercial Energy Efficiency Programs

Target Market: Retrofit

Duration: Okanagan only May – September, 2009

The program focused on the Okanagan Valley because it is geographically concentrated area with a relatively high concentration of restaurants.

Similar low flow spray valve programs exist at other utilities, however some doubt exists as to the ultimate benefits of the technology. Running the Okanagan Spray N' Save pilot has allowed Terasen Gas to gather the data required to more properly assess the merits of low flow spray valves as part of a DSM program offering.

Low flow spray valves were installed free of charge in 276 restaurants, representing 92% of the program's target. An initial arithmetic analysis of the recorded data suggests that each spray valve saves over 8 GJ/year. The program therefore achieved a projected energy savings of 9,513 GJ's, and a TRC of 2.8 over the 5 year life time of the low flow spray valves.

A more empirically driven evaluation study is slated for completion in 2010. The details of the evaluation are provided in Section 5.13.3.2. Refer to Appendix D for further details on the Okanagan Spray N' Save Pilot program and Evaluation of Okanagan Spray N' Save Pilot Program.

4.8.5.2 TGVI Furnace Servicing Pilot

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: TGVI October 2009 – June 30 2010

Customers are rewarded for their service with a $25 Save-On-Foods gift card. The objectives of the pilot were to:

- Provide education and awareness about energy efficient appliances and their maintenance
- Determine if a $25 Gift Card was enough value to incent customers to take action
- Obtain feedback from the trades community on whether the program helped them engage customers in conversations about efficiency, safety and the opportunity to upgrade existing appliances

If the pilot is successful, a similar program will be launched across the province in January of 2011. Due to the Companies' inability to verify savings from the program, direct savings claims cannot be made; however, it can be argued that there is the increased potential for appliance replacements post furnace servicing. The total budget for this program is $224,000 which includes incentives, program administration, marketing, and evaluation of which $199,023 was paid out in 2009. Refer to Appendix D for further details.

4.8.6 Summary

Enabling Activities provide important support for effective EEC program development, delivery and evaluation. Most EEC programs work on the principal of market transformation with eventual mandate by regulation as the end game.

Research and Evaluation provides the information required to develop a market development plan. Pilot Programs verify savings and help identify market barriers. The Efficiency Partners Program aids in efficient delivery of EEC programs and provides the vital industry feedback for program adjustments. Regulation target levels and implementation timeframes require guidance from industry stakeholders.

Given the aggressive BC government provincial emission targets, participation on the various Codes and Standards committees is critical to establish a proper energy balance. Poorly constructed or timed regulations could result in a void of products and services and disrupt market transformation process. Unsuccessful area market transformation could result in an unbalanced shift to one energy source creating a supply and demand problem, resulting in rate increases to the customer base.

The Companies believe that the results of Enabling Activities in 2009 demonstrate their value and intend to continue, refine and improve such activities in 2010.

4.9 EEC Stakeholder Group Activities

In the EEC Application, the Companies recognized the need for accountability for the EEC initiative and proposed to form and engage an EEC Stakeholder Group. The objectives of the EEC Stakeholder Group are to guide and provide input on EEC activity.

4.9.1 Soliciting Appropriate Stakeholder Involvement

The Companies intend to hold biannual EEC workshops with at which the Companies would present updates on program progress; these would also act as a forum for stakeholder input on developing new programs and refining existing programs.

The members of the EEC Stakeholder Group were solicited through Regulatory Stakeholders (those that have historically intervened in the Companies' regulatory proceedings), from industry groups that the Companies' engage with, experts in design of programs and initiatives, and from key contacts from the Companies' Residential, Commercial, and Community Relations departments.

Representation was sought from the following areas within both TGI and TGVI service territories for the stakeholder group:

- Provincial, municipal, and First Nation governments
- Non-Governmental Organizations
- Consumer advocates, representing residential customers
- Affordable housing advocates
- Commercial customers
- Trade organizations
- Equipment manufacturers
- Other utilities

4.9.2 Early Progress from Stakeholder Meetings

The first EEC Stakeholder Group meeting was held on December 9, 2009. As this was the first EEC Stakeholder meeting, the Companies presented an introduction to DSM/EEC, a summary of the EEC Application and the resulting EEC Decision, government regulation, and a general description from each program area of initiatives to come.

A post-meeting survey was emailed to the EEC Stakeholder Group shortly after and received a 65% response rate, with over 90% of respondents stated that they were overall, either very or somewhat satisfied with the first EEC Stakeholder Group meeting. Attendees commented on the strong presenters and expressed their desire to provide ongoing feedback in future meetings.

Appendix F includes the EEC Stakeholder Group members list, and the 2009 EEC Stakeholder Group meeting invitation, agenda, and meeting minutes.

Please also refer to Section 5.14 for the description of the completed and proposed EEC Stakeholder Group activities for 2010.

4.9.3 Summary and Next Steps

The initial meeting was successful in introducing key stakeholders to the EEC Decision and its resulting programs. The EEC Stakeholder Group will provide a forum for open dialogue and feedback on future program design and initiatives.

4.10 Summary 2009 EEC Activities: Successfully Establishing the Foundation

The second half of 2009 represented the inception of the Companies' efforts to develop and execute on the broader EEC mandate; a mandate made possible by earlier Commission approval of funding. While the year could fairly be characterized as one of transition, (from earlier, narrowly focused but successful DSM activities, to the broad efforts of 2010 and beyond), it should also be considered one of meaningful results.

In addition to the establishment of the EEC team, the Company:

- Overall - Established a new, broadened EEC Program Portfolio and Associated Program Areas.

- Residential - Launched two Residential Energy Efficiency retrofit programs: the ENERGY STAR® Heating System Upgrade Program, and the EnerChoice Fireplace Program. The ENERGY STAR® program surpassed its original target of 8,180 furnaces to achieve 15,000 furnace replacements once all applications are processed in 2010.

- Commercial - Expanded its Commercial programs by increasing participation in the Efficient Boiler Program and by continuing to help customers save energy every year through the Energy Assessment Program. Finally, the Companies launched the Light Commercial ENERGY STAR® Boiler program, which is already logging gas savings.

- Affordable Housing - Laid the foundation for the Conservation for Affordable Housing program area, while also rolling out three projects: the Meridian Village Project, the MEMPR Low Income Partnership Funding, and the Energy Conservation for Affordable Housing Forum.

- CEO - Introduced and continued Conservation Education and Outreach Programs, which collectively sought to foster a "culture of conservation". Through targeting powerful media channels, traditional forums such as trade shows, innovative partnerships with local sports clubs and more, the Companies promoted attitudes and values that will increase commitment to EEC activities.

- Enabling - Undertook Enabling Activities that deepened understanding of markets, verified savings, identified market barriers, established relationships with suppliers to the energy efficiency industry, and built upon regulatory policy.

- EEC Stakeholders - Selected the right stakeholders to make up the EEC Stakeholder Group, then provided them with an overview of DSM/EEC, the EEC Application and the resulting EEC Decision, government regulation, and a general description from each program area of initiatives to come.

While these results reflect a partial year of activity for 2009 (most of the programs were rolled out later in the second half of 2009 once the EEC Decision was issued and the staffing resources were set in place), they are nevertheless ones the Companies take pride in. Collectively they represent a strong foundation for EEC activities in the latter part of 2010 and beyond.

5. 2010 PLAN: BUILDING ON THE EEC FOUNDATION

The establishment of an EEC team and broad Program Portfolio in 2009 (and early 2010) provides the Companies with a strong foundation to build on in 2010. The material presented in this section on 2010 planned activity represents only the activity planned at the time of writing. The Companies anticipate that there will be more and other activities undertaken in 2010 as additional opportunities for EEC activity are identified. While the Companies intend to continue with the majority of Portfolio Programs from 2009, they will take steps to refine their effectiveness while introducing three new Program Areas.

5.1 Three New Program Areas

In 2010, the Companies' EEC team plans to further expand the program portfolio by adding three additional Program Areas: High-Carbon Fuel Switching, Interruptible Industrial Program Area and Innovative Technologies.

- The High-Carbon Fuel Switching Program Area lowers GHGs by using natural gas in place of higher carbon fuels such as coal, oil or propane. In addition, further energy savings will be recovered by replacing high-carbon appliances with efficient natural gas appliances such as ENERGY STAR® furnaces or boilers.

- The Interruptible Industrial Program Area implements energy efficiency and conservation activities for these customers, while at the same time managing the risk associated with large financial investments in energy efficiency for interruptible industrial customers and the resulting magnitude of the anticipated energy savings.

- The Innovative Technology Programs will promote and pilot emerging commercially available technologies. The current portfolio of Innovative Technologies includes Solar Thermal Hot Water, NGV for Commercial Vehicles, Hydronic and Combination Space Heating Systems, Residential Ground Source Heat Pumps ("GSHP") and Commercial and Industrial GSHP Systems.

Note that these Program Areas are in the very early stages of their development and as such, their scope is not yet fully formed. It is therefore necessary to engage in further research, and explore and address additional opportunities in these Program Areas as they arise.

5.2 New Program Areas Complement Existing Offerings

This section looks carefully at these three new Program Areas while also examining the set of offerings within existing Program Areas, which will be refined and continued. In aggregate, the Companies believe the Program Areas and associated activities constitute a robust and effective collection of EEC initiatives.

The Program Areas examined in this section are as follows:

5.5 Residential Energy Efficiency;

5.6 Commercial Energy Efficiency;

5.7 High-Carbon Fuel Switching;

5.8 Conservation for Affordable Housing;

5.9 Joint Initiatives;

5.10 Conservation, Education and Outreach;

5.11 Interruptible Industrial Sector;

5.12 Innovative Technologies;

5.13 Enabling Activities;

5.14 EEC Stakeholder Group Activities; and

5.15 2010 EEC Portfolio: Summary.

5.3 Expected Programs

The Companies' EEC Portfolio consists of multiple Program Areas. Each Program Area includes all specifically related programs, measures and activities.

Table 5-1 below shows overall program results including the overall incentive and non-incentive amounts that will be spent on EEC programs, annual energy savings, present value energy savings over measure life, and the TRC results.

Spending in 2010 will increase over 2009, as will expected savings. The total amount budgeted thus far for incentives for 2010 is $7.979 million. This is significantly higher than the 2009 expenditure on incentives of $3.344 million. Similarly, the total non-incentive amount for 2010 is $9.912 million which is again significantly higher than the non-incentive expenditure of $2.917 million for 2009. It should be noted that these are projected activities and expenditures in Q1 2010; as more activities and budgets are developed through the course of the year, projected expenditures and the associated savings will increase. These increases are associated with the increased amount of activity planned for EEC activities in 2010, which will result in higher annual energy savings (208,725 GJs for 2010 vs. 130,965 GJ s for 2009) and the present value of the measure life energy savings is significantly higher in 2010 at 2,031,015 GJs for 2010 than 1,284,100 GJs for 2009.

The projected portfolio TRC result for 2010 is 1.0 which includes non-program expenses that are allocated to the Portfolio level of $8.553 million. While the TRC analysis presented below includes these portfolio-level expenditures on the cost side of the equation, there is currently nothing allocated on the benefit side of equation for these portfolio-level expenditures, even though some of the portfolio-level activity will result in energy savings. This is the case because the Companies do not currently have enough information to be able to estimate with confidence the magnitude of the benefit from some of these portfolio-level expenditures. A key example of this would be in the area of Pilots – the Companies have allocated $1.432 million to Pilots such as the Custom Design Pilot discussed in Section 5.13.6.2. Energy savings will accrue from the Custom Design Pilot, however these savings are unknown at the time of writing and so are not included in the benefits side of the TRC analysis presented below. The Companies are conducting these Pilots in order to determine the benefits from the technologies and systems that are being piloted.

Further, the one-time costs for implementation of the DSMS are included in the portfolio-level expenditures for 2010, as are the one-time costs for the CPR. Similarly, the funds approved for the development of an Interruptible Industrial EEC program are also included in the 2010 portfolio-level TRC. These one-time costs reduce the overall TRC because the Companies account for the costs but these expenditures will provide value over years to come. The Companies will be monitoring the performance of the 2010 portfolio on a monthly basis to ensure that the overall Portfolio level TRC remains at 1.0 or greater and will consult with the EEC Stakeholder group if it appears that the performance of the Portfolio will be challenged by the fact that 2010 is very much a development year, where a number of new programs will be heavily front-end-loaded with pilot, development and promotional costs. The final actual 2010 portfolio-level TRC will be presented in the 2010 Annual Report to be filed in March 2011.

Table 5-1: 2010 Overall Portfolio Will Bring Value to Customers and the Companies

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
TGI	6,447	7,917	14,365	191,183	1,869,069	1.0
TGVI	1,531	1,994	3,526	17,542	161,946	1.1
Total Results	7,979	9,912	17,890	208,725	2,031,015	1.0

5.4 2010 Activities by Program Area Level and Activity

Table 5-2 below shows the results for 2010 activities by Program Area. The work completed in 2009 set the stage for the 2010 EEC portfolio and program activities. In 2010, the Companies plan on continuing to operate a number of existing programs (with some modifications), while rolling out several new incentive programs to the market place. The 2010 EEC portfolio is responsive to the requirements in the DSM Regulation that to be considered adequate, a public utility's plan portfolio submitted after June 1, 2009 should include the following:

a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption (see Section 5.8.3);

b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations (see Section 5.8.3 and 5.8.3);

c) an education program for students enrolled in the public utility's service area (see Section 5.10.2.4);

d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area (see Section 5.10.2.4).

Additional consideration will be given to simplifying program processes and administrative burdens for participants and the Companies. The 2010 programs will aim to meet customer and market needs; for example, high carbon fuel switching program initiatives will provide significant benefits to the Province of BC's GHGs reduction strategy, and increased Conservation for Affordable Housing programs will continue to meet the EEC program principle of universality – offering access to energy efficiency and conservation for all customers.

Other activities will increase the Companies' participation in mutually beneficial collaborations between groups such as government agencies or BC utility partners. CEO programs and Enabling Activities will continue to support, and promote awareness of EEC Activities, which in turn, generate buy-in from partners and desire to participate in program activities from customers.

The Commission's approval of the NSAs confirmed funding of EEC programs through 2011, with the addition of funding for two new Program Areas: Interruptible Industrial Program Area and Innovative Technologies. High-Carbon Fuel Switching was approved in the EEC Decision in 2009. These new Program Areas will see the development and delivery of programs in the second half of 2010, and through 2011. In 2011, the Companies plan to file an application to the Commission related to EEC funding for the timeframe beyond 2011, so preparation for this filing will commence in the latter part of 2010.

Table 5-2: 2010 Programs Will Bring Value to Customers and the Companies

Program Area	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
Residential Programs	**2,791**	**220**	**74,906**	**755,601**	**1.4**
TGI	2,561	180	68,385	692,757	1.3
TGVI	230	40	6,521	62,844	1.5
Commercial Programs	**1,527**	**346**	**112,562**	**1,106,704**	**2.1**
TGI	1,332	277	97,730	956,981	2.1
TGVI	194	69	14,832	149,722	2.2
High Carbon Fuel Switching	**750**	**225**	**(16,125)**	**(169,145)**	**1.5**
TGI	225	25	(4,838)	(50,954)	1.6
TGVI	525	200	(11,288)	(118,191)	1.4
Conservation for Affordable Housing	**2,911**	**567**	**37,382**	**337,855**	**0.0**
TGI	2,329	454	29,905	270,285	0.0
TGVI	582	113	7,476	67,571	1.0
Joint Initiatives (TGI & TGVI)	N/A	**717**	N/A	N/A	N/A
Conservation, Education & Outreach (TGI & TGVI)	N/A	**1,775**	N/A	N/A	N/A
Enabling Activities (TGI & TGVI)	N/A	**439**	N/A	N/A	N/A
Interruptible Industrial DSM (TGI & TGVI)	N/A	**435**	N/A	N/A	N/A
Other Portfolio Level Activities (TGI &TGVI)*	N/A	**5,188**	N/A	N/A	N/A
Total	**7,979**	**9,912**	**208,725**	**2,031,015**	**1.0**

*Other Portfolio Level Activities include CPR, Research, Evaluation & Training, Consultants' fees, implementation of DSM Tracking System, Pilot Programs, efficiency partners programs and non-program administration activities (labour costs)

Note that the "Other Portfolio Level Activities" include a number of portfolio-level items. For 2010 these activities and the costs associated with them are listed below:

- Conservation Potential Review ($500,000)
- Research, Evaluation and Training ($906,587)

- Consultant Fees ($100,000)
- Efficiency Partners and Codes and Standards ($439,000)
- Implementation of DSM Tracking System ($704,000)
- Pilot Programs ($1,432,500)
- Labour Costs ($1,545,000)

As shown in the Table 5-1 and 5-2 above, the EEC portfolio in 2010 will bring value to customers and the Companies. The details of each Program Area are further discussed in the following sub-sections.

5.5 Residential Energy Efficiency Programs

In 2010, the Companies plan on completing the existing 2009 Residential Energy Efficiency programs, while rolling out several new incentive programs to the market place. The programs are categorized as: 2009 programs that are under completion, new programs being launched in Q1 and Q2 in 2010, and programs under consideration for Q3 and Q4. Table 5-3 provides a summary of the 2010 Residential Energy Efficiency programs for TGI and TGVI.

5.5.1 Program Goals

2010 Residential Energy Efficiency programs are focused on the following general objectives:

- Upgrade existing low efficiency systems to capture energy savings associated with reducing the overall consumption of natural gas. The focus in 2010 will be on hot water heaters, fireplaces, and possibly a furnace early retirement program.
- Prepare the market for the adoption of new energy efficient technologies through incentive programs and support of government regulations. The focus in 2010 will be on domestic hot water technologies. A program for 0.61 Efficiency Factor ("EF") tanks will be launched in Q2. During Q3 and Q4, the Companies plan to conduct pilots for Tier 3 water tanks (0.80 EF and higher) in order to develop programs for 2011 and beyond. (Please refer to Section 5.13.6 for information about these pilots.)
- Introduce programs for new home construction to ensure that all new homes adopt the latest energy efficient technologies and provide incentives where necessary.
- Educate the trades community about upcoming regulations and gain an understanding of technical requirements or other barriers associated with new product introductions
- Educate consumers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary. Take the opportunity to incorporate energy conservation messaging within program marketing materials.
- Engage manufacturers by supporting new technologies and providing advertising opportunities to the Companies' customer base

- Develop cost effective programs with a TRC greater than 1.0 that optimize the proportion of incentives over administration and marketing costs
- Conduct program evaluation that confirms savings claims and guides program development of future programs.

5.5.2 Residential Energy Efficiency Programs – Portfolio Overview: New and Existing Programs

Generally speaking, the Companies' 2010 residential EEC programs fall into three categories. There are 2009 programs that are ongoing and expected to be completed in 2010. There are new programs launching in Q1 and Q2 and there are programs under consideration for launch. The chart below outlines the programs in each category and their associated costs and savings.

Table 5-3: 2010 Residential Energy Efficiency Programs for TGI and TGVI

<table>
<tr><th rowspan="3"></th><th rowspan="3">Program</th><th rowspan="3">Description</th><th colspan="2">New Construction</th><th colspan="2">Retrofit</th><th colspan="2"></th></tr>
<tr><th rowspan="2">Incentive & Non-Incentive Expenditure</th><th rowspan="2">NPV Energy Savings</th><th rowspan="2">Incentive & Non-Incentive Expenditure</th><th rowspan="2">NPV Energy Savings</th><th colspan="2">TRC</th></tr>
<tr><th>TGI</th><th>TGVI</th></tr>
<tr><td></td><td colspan="8">2009 Programs Under Completion</td></tr>
<tr><td rowspan="2">1</td><td>ENERGY STAR® Heating System Upgrade - 2009</td><td>$250 Incentive for upgrading heating system to Energy Star rated appliance</td><td colspan="2" rowspan="2">N/A</td><td>977</td><td>249,358</td><td>1.2</td><td>1.1</td></tr>
<tr><td>ENERGY STAR® Heating System Upgrade - LiveSmart BC - 2009</td><td>$250 Incentive for upgrading heating system to Energy Star rated appliance as part of LiveSmart BC incentive portfolio</td><td>974</td><td>255,496</td><td>1.2</td><td>1.1</td></tr>
<tr><td></td><td colspan="8">2010 Programs Launching in Q2</td></tr>
<tr><td>2</td><td>Domestic Hot Water 62% ENERGY STAR® Tanks</td><td>$50 Consumer Incentive and $50 Contractors Incentive to prepare the market for new regulations</td><td colspan="2" rowspan="2">Under Development</td><td>460</td><td>49,869</td><td>0.8</td><td>0.8</td></tr>
<tr><td>3</td><td>EnerChoice Fireplace Consumer Incentive - 2010</td><td>$100 consumer coupon to incent customers to choose EnerChoice</td><td>600</td><td>200,878</td><td>2.8</td><td>2.8</td></tr>
<tr><td></td><td colspan="8">2010 Energy Efficiency Residential Programs Under Consideration</td></tr>
<tr><td>4</td><td>Furnace - Early Retirement Program</td><td>Re-educate market about high efficiency furnaces and urge customers to upgrade early</td><td colspan="2" rowspan="2">N/A</td><td colspan="2" rowspan="2">Under Development</td><td colspan="2" rowspan="2">Under Development</td></tr>
<tr><td>5</td><td>Furnace Service Campaign - "Give your furnace some TLC"</td><td>Educate the market about the importance of appliance maintenance and create opportunities to upgrade appliances for efficiency</td></tr>
</table>

The highlights of the 2009 retrofit energy efficiency programs under completion are as follows:

- The ENERGY STAR® Heating System Upgrade Program, including participants from LiveSmart BC, will surpass the EEC application replacement target of 8180 furnaces or boilers, with expectations of 15,000 participants. Final overview of program performance will be presented in the Companies' Report on 2010 EEC activities, to be presented by the end of Q1 2011.

The highlights of 2010 retrofit and new construction energy efficiency programs are as follows:

- The ENERGY STAR® Hot Water Heater Retrofit Program (61%+ EF) is being launched in Q2 to prepare the trades community for the implementation of the September 1, 2010 provincial regulations requiring 61% EF minimum efficiency levels, and educate consumers about ENERGY STAR® water tanks.

- The EnerChoice Fireplace Retrofit program will educate consumers about the merits of choosing energy efficient fireplaces.

The highlights of new programs under consideration are as follows:

- The ENERGY STAR® Hot Water Heater New Construction Program will be launched in Q2 with the objective of ensuring that all new homes adopt the energy efficient hot water heaters.
- The EnerChoice Fireplace New Construction Program will be launched in Q2 with the objective of ensuring that all new homes adopt energy efficient natural gas fireplaces.
- A Furnace Early Retirement Program may be launched based on stakeholder feedback on the numbers of mid-efficient furnace inventory remaining for sale and the results of economic modelling.
- A Furnace Service Program, based on the TGVI pilot (refer to Section 4.8.5.2) may be launched province-wide during the summer months that are generally a slow time for gas contractors.

The Residential Energy Efficiency programs for 2010 are described in further detail below.

5.5.2.1 ENERGY STAR® Heating System Upgrade Program

It is anticipated that the ENERGY STAR® Heating System Upgrade Program (which includes participants from LiveSmart BC) will surpass the EEC application replacement target of 8180 furnaces or boilers, with expectations of well over 15,000 participants. This will make it a tremendously successful Program in the Residential portfolio.

Although this Program completed in 2009, it is discussed here because the application deadline for the Companies' program is March 31, 2010 and participant data from the LiveSmart BC program may not be received until the second quarter of 2010. Therefore, the final program overview will be reported in the Companies' EEC report on 2010, once all final participation numbers have been received.

Table 5-4 outlines the energy savings estimates for participants that will be processed in 2010. In this period, it is projected that an additional $1.9 million in incentives will be distributed generating an additional 504,854 GJ's in energy savings over the life time of the measure.

Table 5-4: ENERGY STAR® Heating System Upgrade Participants Processed in 2010 forecasts significant energy savings within a cost-effective program

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
The Companies	TGI	3,609	902	40	22,916	241,380	43%	1.2
	TGVI	120	30	5	762	7,979	43%	1.1
LiveSmart BC	TGI	3,635	909	10	23,082	242,246	43%	1.2
	TGVI	200	50	5	1,270	13,250	43%	1.1
Total	**TGI**	**7,244**	**1,811**	**50**	**45,998**	**483,626**	**43%**	**1.2**
	TGVI	**320**	**80**	**10**	**2,032**	**21,229**	**43%**	**1.1**

Note: The Companies Participation Rates are based on the estimated number of bill credits issued from January 1, 2010 through to completion of application processing by ABSU (expected April 30, 2010.) The LiveSmart BC participant numbers are an estimate of the total number of heating systems invoiced to TGI/TGVI in 2010 (expected June 30, 2010). This is an estimate from MEMPR based on 2009 trends and is subject to change. The forecasted number of heating systems from MEMPR's LiveSmart BC participant data is a total of 8000, of which 3835 are for the 2010 invoicing period. Full program overview will be presented in the 2010 EEC Report.

For cost benefit analysis please refer to Appendix J.

5.5.2.2 ENERGY STAR® Domestic Hot Water Heater Retrofit Program

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: TGI & TGVI: May 1, 2010 through April 1, 2011

Incentive:

$50 rebate cheque for consumer
$50 rebate cheque for contractor / Point of Sale Contact

Program Administration:

Consumer-Response Marketing

Program Objectives:

- Educate the market about the introduction of provincial regulations on September 1, 2010

- Educate consumers about ENERGY STAR® water heaters and the importance of hot water conservation
- Upgrade a minimum of 3600 Hot Water Heaters to 0.61 EF or higher
- Promote contractor relations between the Companies and contractors, as well as between contractors and customers
- Engage manufacturers and distributors through co-marketing opportunities
- Engage manufacturers in labelling tanks for Efficiency Factor

Background:

The primary program objective is to educate the market about September 1, 2010 changes to the BC Energy Efficiency Act Standards for gas and propane fired water heaters outlined in MEMPR Information Bulletin 09-05[11]. The secondary program objective is to reap the energy savings associated with upgrading water heating systems.

BC provincial regulations require that all water tanks manufactured after September 1, 2010 be Tier One with an efficiency rating of at least 0.61 depending on tank size. Program benefits include education and outreach to consumers, trades, distributors, Big Box and small retailers, and manufacturers. One program challenge is the fact that manufacturers do not label water heaters with efficiency ratings. Manufacturer engagement will be an important component of the program.

Estimates of hot water energy consumption as a percentage of household energy use range from 15% (2006 Terasen Gas Conservation Potential Review ("CPR")) to 30% (BC Govt Energy Efficient Building Strategy). The CPR states that Domestic Hot Water ("DHW") accounts for 21% of residential natural gas consumption and notes a 2% annual energy improvement as hot water systems are upgraded. Even greater savings will be realized as water heating appliances become more efficient.

BC's hot water tank market is difficult to estimate. The following data is collected from the Canadian Institute of Plumbing and Heating ("CIPH"), MEMPR 2008, and the 2008 REUS.

- 60% of the residential market is comprised of natural gas hot water tanks.
- Based on estimates from CIPH, approximately 121,409 hot water tanks are sold annually in BC.
- 68,840 are natural gas tanks and of those, 20% are high efficiency models, meaning 0.61 EF and greater.

Water tank statistics from the 2008 REUS include the following:

- 89% of the Companies customers have gas hot water tanks
- 38% of the Companies customers have replaced water tanks over the past five years which by calculation represents a 7.6% annual churn rate.
- Of those that are replaced:
  - 83% are only done at the time of failure or imminent failure
  - 9% were undertaken for the purpose of increasing energy efficiency

[11] Please refer to Appendix C for the MEMPR Information Bulletin 09-05. *BC Energy Efficiency Act Standards: Gas and Propane-Fired Water Heaters*.

The $50 Consumer Incentive will drive public awareness about the importance of water tank efficiency, increase prominence of the ENERGY STAR® label, urge customers to be proactive about the water tank purchase decision, and provide an opportunity to raise awareness about the importance of hot water conservation. By developing this program, we are encouraging customers to request high efficiency water heaters in all retrofit situations. However, this process will take time to drive market transformation.

A $50 Contractor Incentive will urge contractors and distributors to promote efficient water tanks. Since the large majority of purchase decisions are completed out of necessity due to tank failure, customers are reliant on independent contractors to provide energy efficient appliances and advise them on the benefits of choosing energy efficient appliances.

Please refer to Appendix D for detailed program description.

Projected Outcome:

Table 5-5 provides highlights of the ENERGY STAR® Hot Water Program energy savings estimates:

Table 5-5: ENERGY STAR® Domestic Hot Water Heater Performance Forecast indicates a marginal cost benefit test although regulation compliance is the most important aspect of this program

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	TGI	3,000	300	80	4,800	41,589	20%	0.8
	TGVI	600	60	20	960	8,280	20%	0.8

*In the retrofit program, the number of participants actually refers to number of units (water tanks sold). This is a split incentive between between contractor and customer. Distributing two cheques per unit will cost more and thus the administration costs are higher on the retrofit program over new construction.

As outlined in Table 5-5, the projected program participant target of 3,600 is achievable with a modest marketing budget. By offering an incentive for both the contractor and for the consumer buy-in from one or both stakeholders will help drive program participation. Through bill inserts, The Companies have a cost-effective direct-to-consumer marketing channel. Through mail-outs to the BC Safety Authority Registered Contractor database, the Companies have a cost-effective direct to trades marketing channel. Furthering the relationship between trades and consumers will drive the promotion of all energy efficiency programs.

The projected spending forecast is $360,000 in incentives and $100,000 for non-incentives. Non-incentive spend is less than 30% of total spend. The program is forecasted to achieve annual gas savings of 5760 GJ's and close to 50,000 GJ's over the lifetime of the measure. Although the TRC for this program is marginally less than 1.0, the program is an important component in an overall campaign to help manufacturers, distributors, installers, and customers prepare for new Provincial regulations, in effect September 1, 2010, which require that all Hot Water Heaters manufactured after that date be Tier One. By planning and promoting this program in conjunction with MEMPR, the Companies are building an important relationship and demonstrating a willingness to support regulations and efficiency compliance among trades.

Program evaluation will include billing analysis in 2012 and potentially surveys to distributors and contractors to monitor the trends in market penetration of ENERGY STAR® eligible models.

For cost benefit analysis please refer to Appendix J.

Summary:

The market information presented demonstrates the great need for Energy Efficiency education across the hot water equipment supply chain – from manufacturers and distributors through to consumer education. Through the joint incentive, provided to customers and installers, the program is also designed to increase awareness of the ENERGY STAR® brand, and to help ensure that customers who are replacing their tank in an emergency situation both choose install an ENERGY STAR® (or equivalent) tank and have access to an ENERGY STAR® (or equivalent) tank through their installer.

This program is an important component in an overall strategy to help manufacturers, distributors, installers, and customers prepare and adopt new Provincial regulations, in effect September 1, 2010, which require that all Hot Water Tanks manufactured after that date be Tier One. The Companies will be actively evaluating Tier Three Technologies (>0.8 EF) and developing a market transformation strategy. Please refer to Section 5.13.6.4 for more information about Tier 3 pilot programs that will be launched in Q3 and Q4.

5.5.2.3 EnerChoice Fireplace Consumer Incentive Program

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: May 2010 through April 2011, with possible extension

Incentive: $150 (proposed)

Partners: HPBAC

Program Administration:

Consumer Response Marketing Ltd.

Program Objectives:

- Encourage the sale and installation of energy efficient heater style fireplaces to reap the associated energy savings.
- Further the education and awareness of the EnerChoice label to consumers and industry.
- Further relationships with manufacturers and distributors of natural gas fireplaces, through the HPBAC.

- Develop a cost effective program with TRC greater than 1.0 and maximize the proportion of incentives over administration and marketing costs

Background:

Promoting energy efficient fireplaces is an important component to EEC programs. Natural gas fireplaces account for 13% of residential natural gas consumption (2006 CPR), and 85% of customers have at least one fireplace or heating stove (2008 REUS). Through this program the Companies are encouraging their customers to adopt energy efficient gas fireplaces designed for heating rather than simply decorative fireplaces for ambience.

In 2009, TGI and TGVI offered fireplace retailers the opportunity to receive a $50 SPIFF for educating customers and promoting the purchase of energy efficient fireplaces. According to the HPBAC members, the marketing campaign and manufacturer's coupons were well-received. They believe that dealers are now well educated on the merits of EnerChoice fireplaces coming out of the 2008 and 2009 TGI programs and 2009 TGVI programs.

In order to further educate consumers about the merits of energy efficient fireplaces, the 2010 EnerChoice program will provide a $150 consumer rebate for EnerChoice purchases. TGI and TGVI will engage HPBAC members to co-promote the offer through retailer and manufacturer channels. Promotions will include bill inserts, advertisements in community newspapers, summer home shows, Team Terasen, online media purchase, and partnering with associations and NGO's.

Please refer to Appendix D for detailed program description.

Projected Outcome:

Table 5-6 provides program highlights of the EnerChoice Fireplace Consumer Incentive Program performance metrics for 2010 based on our forecast.

Table 5-6: EnerChoice Fireplace Consumer Incentive Performance Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	TGI	3,000	450	50	17,670	167,542	24%	2.8
	TGVI	600	90	10	3,534	33,336	24%	2.8

The projected participation rates of 3600 participants should be achievable when partnering with HPBAC members to cost-effectively drive the program The Free Rider Rate is 24% based on previous customer surveys.

As outlined in Table 5-6 the projected spending forecast is $540,000 in incentives and $60,000 for non-incentives. The program is forecasted to achieve annual gas savings of 21,000 GJ's and 200,000 GJ's over the life time of the measure.

Program evaluation from 2008 and 2009 programs will help determine the future direction of EnerChoice programs.

For cost benefit analysis please refer to Appendix J.

Summary:

With fireplaces using 13% of residential natural gas consumption, it is critical to educate homeowners about the importance of choosing energy efficient models. As more models become available the minimum efficiency standard can be increased over time. The Companies will continue to foster their relationship with HPBAC to assist in driving fireplace efficiency.

5.5.2.4 ENERGY STAR® Domestic Hot Water Heater New Construction (Under Development)

Program Area: Residential Energy Efficiency Programs

Target Market: New Construction

Duration: To be Determined

Incentive: To be Determined

Program Objectives:

- Educate the market about the introduction of provincial regulations on September 1, 2010
- Encourage the sale and installation of energy efficient water heaters to reap the associated energy savings.
- Educate builders and developers about ENERGY STAR® water heaters and the importance of hot water conservation

Background:

The Companies' goal is to promote the adoption of the latest energy efficient appliances as standard practice for new construction. Incentive programs help build this awareness. The $100 incentive will go to the builder or developer of a new home, to encourage the installation of ENERGY STAR® Domestic Hot Water heater. The new construction component of the ENERGY STAR® Domestic Hot Water program has not been finalized at the time of writing but will be based on the retrofit program assumptions and processes.

5.5.2.5 EnerChoice Fireplace New Construction Component (Under Development)

Program Area: Residential Energy Efficiency Programs

Target Market: New Construction

Duration: To be determined

Incentive: To be determined

Program Objectives:

- Encourage the sale and installation of energy efficient heater style fireplaces to reap the associated energy savings.
- Further the education and awareness of the EnerChoice label to builders and developers.
- Further relationships with manufacturers and distributors of natural gas fireplaces, through the HPBAC.

Background:

The Companies' goal is to promote the adoption of the latest energy efficient appliances as standard practice for new construction. Incentive programs help build this awareness. The $150 incentive will go to the developer or builder of a new home. The opportunity to extend this program to multi-family residential is under consideration based on further research. The new construction program has not been finalized at the time of writing but will be based on the retrofit program assumptions and processes.

5.5.2.6 Furnace Early Retirement Program (Under Development)

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: To be determined

Incentive: To be determined

Program Objectives:

If research suggests the program is viable, the Companies may consider launching an ENERGY STAR® Heating System Early Retirement program, with a limited time offer. This program will educate homeowners about the value of high efficiency ENERGY STAR® furnaces and persuade homeowners to make a proactive replacement decision for additional energy savings.

Background:

The 2008 REUS suggests that only 16% of the Companies' customers have high efficiency furnaces (90% AFUE and higher), 39% have mid-efficiency furnaces (78% to 85% AFUE), and 45% have standard efficiency (less than 78% AFUE) furnaces. This means that 45% of the Companies' customers have an urgent need to upgrade their standard efficiency furnaces – some of which may have efficiency levels as low as 55%. This Program, should it be launched, would be designed to promote and encourage upgrades to high efficiency furnaces.

This program is in the early stages of development and still requires discussions with a large number of stakeholders. The Companies are evaluating available market and technical data to establish a sound business case and cost benefit analysis before proceeding.

Inventory stocks must be assessed. Although the BC Energy Efficiency Act Standards for Gas Furnaces applies to furnaces manufactured after December 31, 2009, mid-efficiency models can still be sold. Therefore there remains a large inventory of mid-efficiency furnaces in the market. The Companies are gathering industry feedback to estimate the size of the leftover mid-efficiency inventory.

The Companies are also gathering anecdotal evidence of lower efficiency furnaces that are due for replacement remaining in place and having repairs "jerry rigged" as a way to avoid some of the venting issues that British Columbians may face with the introduction of government's 90% efficient furnace regulation.

5.5.2.7 Furnace Service ("Give Your Furnace Some TLC") Program (Under Development)

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: To be determined

Incentive: $25 Save-On Foods Gift Card

Program Objectives:

The primary objectives of the program will be:

- Provide education and awareness about energy efficient appliances and their maintenance
- Engage customers and contractors in conversations about efficiency, safety and the opportunity to upgrade existing appliances

No direct savings claims can be made from this program however the spillover effects would be appliance replacement.

Background:

In 2009, the EEC team developed the TGVI furnace servicing pilot program, "Give Your Furnace Some TLC," to promote the benefits of annual furnace servicing. The program was successful with over 300 applications received within 8 weeks of launching the program, demonstrating that customers will respond well to a $25 gift card incentive. Due to the success of the pilot, the Companies intend to roll out the program across the province in the summer of 2010.

5.5.3 Summary

Building on the success of the 2009 Residential Energy Efficiency Programs, 2010 programs will focus on energy savings associated with hot water heaters, fireplaces, a furnace service program, and possibly a furnace early retirement program. The Companies are also assessing opportunities for the New Construction market. In addition to energy and GHG savings, the programs will assist the provincial government with engaging industry in compliance with regulations, include conservation messaging in program outreach materials, and engage the trades, suppliers and manufacturers.. These programs are critical to the Companies' role in driving market transformation in the residential sector.

5.6 Commercial Energy Efficiency Programs

The Companies' commitment to Commercial Energy Efficiency programs was demonstrated in the 2009 initiatives described in Section 4.4. In 2010, the Companies plan on continuing to operate a number of these existing programs (with some modifications), while rolling out several new energy efficiency incentive programs to the market place.

5.6.1 Program Goals

Commercial Energy Efficiency programs focus on the following objectives:

- Upgrade existing low efficiency systems to capture energy savings associated with reducing the overall consumption of natural gas
- Prepare the market for the adoption of new energy efficient technologies through incentives, and support of government regulations.
- Educate commercial customers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary.
- Engage the trades community and manufacturers by supporting new, energy efficient technologies.
- Develop cost effective programs with a TRC greater than 1.0 that optimize the proportion of incentives over administration and marketing costs
- Conduct program evaluations that confirm savings claims and guide the development of future programs.

5.6.2 Commercial Energy Efficiency Programs – Portfolio Overview: New and Existing Programs

The focus of 2010 will be to build on successes while broadening offerings to capitalize on new opportunities to promote Commercial Energy Efficiency programs.

Existing programs which will be continued and/or improved include:

- Efficient Boiler Program;
- Light Commercial ENERGY STAR® Boiler Program; and
- Energy Assessment Program.

New programs for 2010 will include the;

- Efficient Commercial Water Heater Program;
- Commercial Cooking Program;
- Commissioning Program; and
- Process Heat Program.

Table 5-7 provides a summary of the 2010 Commercial Energy Efficiency programs for TGI and TGVI.

Table 5-7: Solid performance expected again in 2010

	Program	Description	New Construction		Retrofit		TRC	
			Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TGI	TGVI
1	Efficient Boiler Program	Rebate program for high efficiency commerical boilers > 300 MBH Input	148	99,200	1,068	724,574	2.1	2.0
2	Light Commercial Energy Star Boiler Program	Rebate program for high efficiency commerical boilers < 300 MBH Input	37	25,821	235	131,721	3.4	3.4
3	Efficient Commercial Water Heater Program	Rebate program for high efficiency commercial water heaters with thermal efficiency > 84%	91	21,193	214	49,959	1.1	1.0
4	Energy Assessment Program	No charge energy use assessments of commercial facilities	N/A		80	24,538	2.6	2.1
5	Process Heat Program	Rebate program targeted at Manufacturing processes	Under Development					
6	Commercial Cooking Program	Rebate program targeted at commercial cooking appliances	Under Development					
7	Commissioning Program	Incentive program to capture energy savings via building comissioning	Under Development					
8	Victoria Spray N' Save Program	Free provision and install of low flow pre rinse spray valves. Partnership with BC Hydro	Under Development					

Both existing and new programs in this Portfolio are expected to deliver value. The anticipated benefits from the 2010 existing Commercial Energy Efficiency programs are as follows:

- The Efficient Boiler Program will continue to generate gas savings in 2010. The Companies look forward to extending the incentive to include domestic hot water heating in combination heat / hot water systems, as well as simplifying the program process. These measures combined with improved program promotions should contribute to increase participation in 2010.

- In 2010 the Light Commercial ENERGY STAR® Boiler Program will provide strong value via TRC performance, while reducing commercial sector gas consumption. A sustained effort at raising the program's profile should lead to increased participation.
- The Energy Assessment Program will see changes aimed at increasing its effectiveness at getting participants to implement energy savings measures. Additional administrative changes will be implemented to avoid double counting of gas savings where such may be attributed to either the energy assessment program, or one of the Companies' other incentive programs.

The 2010 new Commercial Energy Efficiency programs are also expected to produce meaningful results in the following ways:

- The new Efficient Water Heater Program will round out the Companies' incentive offering for high efficiency potable water heating equipment. 2010 will be a learning year which will set the tone for the future of the program.
- The Commercial Cooking Program will provide rebates to reduce the incremental cost of high efficiency commercial kitchen appliances and help drive their adoption by the market.
- The Commissioning Program will capture gas savings by encouraging owners to critically examine their building or facility's operating performance and take simple yet powerful, operationally focused steps to reduce gas consumption.
- The Process Heat program will enable the Companies to assist manufacturing, agricultural and light industrial customers reduce their gas consumption by reducing the incremental cost of investing in high efficiency process heating appliances. The program is likely to be built around high efficiency boilers, though it may include incentives for additional measures.

The Commercial Energy Efficiency programs for 2010 are described in further detail below.

5.6.2.1 Efficient Boiler Program

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: 2005 – December 31, 2011
TGVI: 2005 – December 31, 2011

Program Updates for 2010:

For 2010, the program will be subject to several initiatives aimed at addressing the issues noted in Section 4.4.3, and encouraging increased participation:

1. The program's terms and conditions will be modified to include domestic hot water loads in the incentive calculation providing the program will maintain a healthy positive TRC. This will increase the value of the incentive and explicitly recognize the value of generating potable hot water from a high efficiency source.

2. The Companies will organize a program stakeholder feedback session, including contractors, suppliers, governing authorities and major customers, to gather input on the program design from the market. This will accomplish two objectives: It will help raise awareness of the program and, it will provide needed and direct insight from industry participants on the program's structure and operation.

3. Subsequent to the stakeholder feedback session the Companies will work to simplify and adapt the program's process and update its communications collateral in view of:
    - Making it easier / simpler for participants to take advantage of the program
    - Educating participants on boilers and the steps involved in their installation
    - Reducing the program's administrative burden / overhead

Background:

As discussed in Section 4.4.3, the Efficient Boiler Program is TGI and TGVI's flagship Commercial Energy Efficiency program. Its aim is to reduce gas consumption associated with space heating.

Results in 2009 were generally positive as the Programs saw strong performance despite an underperforming economy. On the other hand, participation from certain sectors – New Construction, Vancouver Island – was noticeably absent.

Please refer to Appendix D for a detailed program description.

Projected Outcome:

The Companies believe that the Efficient Boiler Program will continue to provide solid performance throughout 2010.

Table 5-8 provides program highlights of the Efficient Boiler Program performance metrics for 2010 based on our forecast.

Table 5-8: Efficient Boiler Program continues to reduce gas consumption in 2010

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	TGI	8	103	13	7,137	79,461	18%	2.1
	TGVI	2	26	6	1,784	19,739	18%	2.0
Retrofit	TGI	65	835	107	57,990	645,619	18%	2.1
	TGVI	8	103	24	7,137	78,955	18%	2.0

As noted above, there are, however changes envisioned for the program in 2010. All of the changes will ultimately be designed to encourage additional customers to participate in the program by increasing the value of the incentive, and reducing the administrative burden currently imposed on those who wish to participate. Increasing the program's participant numbers furthers the Companies' goal of reducing the commercial sector's gas consumption and bringing about market transformation.

While the Companies do expect the programs participation numbers to increase in 2010 versus those of 2009, some dampening effect is to be expected as the lag effect from the poor economic climate in 2009 carries through in the construction sector through much of 2010. Participation from the New Construction market seems likely to increase at a modest pace as many multi residential projects, which may have applied for an incentive in 2010, were put on hold in 2009.

For cost benefit analysis please refer to Appendix J.

Summary:

In 2010 the Companies plan to perform an in-depth evaluation study on the program's performance in reducing gas consumption. The results of this study will serve to confirm and/or provide additional insight into the gas savings associated with the program. For additional information on the proposed evaluation study please refer to Section 5.13.3.1.

5.6.2.2 Light Commercial ENERGY STAR® Boiler Program

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: August 2009 – December 31, 2011
TGVI: August 2009 – December 31, 2011

Program Updates for 2010:

Because the program is still relatively new, changes or updates to the program will be limited in 2010 as the Companies gather feedback from participants. The program's initially strong TRC performance suggests that there is some opportunity to adjust the program in view of attracting additional participants. Such a change may be made later in the year and could include:

- An increase to the value of the participant's incentive
- A sales incentive for boiler distributors to encourage the sale of ENERGY STAR® boilers
- An installation incentive for contractors to encourage them to install ENERGY STAR® boilers

Background:

Launched in August 2009, the Light Commercial ENERGY STAR® Boiler Program is the Companies' most recent offering aimed at reducing energy consumption associated with space heating. Program objectives for 2010 are the same as those outlined in Section 4.4.4, the 2009 Light Commercial ENERGY STAR® Boiler Program.

Please refer to Appendix D for a detailed program description.

Projected Outcome:

Table 5-9 provides program highlights of the Light Commercial ENERGY STAR® Boiler Program forecasted performance metrics for 2010.

Table 5-9: Light Commercial ENERGY STAR® Boiler Program to gain market traction

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	TGI	5	14	9	1,453	16,177	18%	3.4
	TGVI	3	9	5	872	9,644	18%	3.4
Retrofit	TGI	40	115	75	11,624	129,270	18%	3.4
	TGVI	10	29	16	2,906	2,451	18%	3.4

The Light Commercial ENERGY STAR® Boiler program is expected to turn in a TRC performance in 2010 more or less in line with what has been seen in 2009. Contributing to the program's forecasted strong performance in terms of TRC is its relative simplicity. This serves to make participation easier for customers and keeps administrative overhead low for the Companies.

Participation should improve throughout the year though as a new program, a sustained effort at program promotions is essential to raise awareness of and ensure increased participation. To garner participants for TGVI the profile of the EEC programs needs to be raised on Vancouver Island. Sustained promotional efforts in conjunction with the Efficiency Partners are expected to significantly address this situation moving forward. As more market participants become aware of the program and the benefits of installing high performance boilers, participation in the Light Commercial ENERGY STAR® boiler program is expected to exceed what was seen in 2009.

For cost benefit analysis please refer to Appendix J.

Summary:

A performance evaluation study will be conducted on the program towards the end of 2010 or early in 2011. While the cost of this study has not been firmly established as of the writing of this report, it is not expected to exceed the $30,000 estimated cost of the Efficient Boiler Program performance evaluation. A $30,000 charge for program evaluation has been included in the numbers presented above.

5.6.2.3 Efficient Commercial Water Heater Program

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: April, 2010 – December 31, 2011
TGVI: April, 2010 – December 31, 2011

Incentive:

Providing that the water heater is used for domestic water heating only:

Storage water heaters / Hot water supply boilers
- $5 per MBH[12] for water heaters with a thermal efficiency of 90% or higher
- $3 per MBH for water heaters with a thermal efficiency of 84% to 89.9%

On-demand water heaters
- $2.50 per MBH for water heaters with a thermal efficiency of 90% or higher

Program Objectives:

The Companies will be making the Efficient Water Heater program available to their commercial customers in early 2010. Through this program the Companies intend to:

- Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency water heaters for domestic hot water heating.
- Increase year over year participation rates in view of maximizing gas savings and bringing about market transformation.
- Educate commercial customers about the advantages of high efficiency water heaters and provide an incentive to facilitate the purchase of high efficiency technology.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
- Prepare the way for and support any provincial regulation requiring increased water heater efficiency.
- Given that one of the targets for this program is Multi-Family Residential Buildings, this program will satisfy clause 3(a) of the DSM Regulation, which states that in order to be considered adequate, a utility's plan portfolio must include measures for rental accommodation.

[12] Note: 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

Background:

The 2006 CPR identifies water heating as the commercial sector's second greatest source of natural gas consumption by volume, at around 14% percent of the total. Yet despite their prevalence, few water heaters are as efficient as they could be. This presents an opportunity for a program that encourages commercial enterprises to upgrade or purchase heaters that are more efficient.

The need is clear: data from the Air-Conditioning, Heating, and Refrigeration Institute ("AHRI")[13], Consortium for Energy Efficiency ("CEE")[14] and discussions with manufacturer's reps indicates a maximum combustion efficiency of approximately 80%. High efficiency water heating equipment is generally "condensing" type with a combustion efficiency of approximately 95%. Moreover, the penetration rate of high efficiency technologies in the DWH market is low[15], especially for stand-alone DHW plants.

Uptake of the more efficient technology is inhibited by several barriers:

1. Higher initial cost / length of simple payback
2. Lack of awareness of products available
3. Nature of replacement market (Emergency replacement handled entirely by a plumber or gas fitter)
4. Negative perception of high efficiency technologies
5. Skeptical as to positive net benefits
6. Split Incentives

As a result, the existing market momentum favours the continued installation of standard efficiency units. While the existing boiler programs will provide a financial incentive for customers who generate DHW in combination space heat/DHW plants, a gap in market coverage exists for segments which make use of standalone DHW plants. The new Efficient Water heater program will bridge this gap.

Targeting Heavy Users:

The program is expected to appeal primarily to commercial customers who typically exhibit high domestic hot water usage such as:

- Commercial Kitchens
- Multi-Unit Residential Buildings
- Hotels/Motels
- Laundries

Some limited participation may be expected from other sectors such as:

- Hospitals & Medical Facilities

[13] *AHRI Database of Certified Product Performance, Water heaters*, available at: http://www.ahridirectory.org/
[14] "Market and Technology Characterization for Commercial GasWater Heaters", CEE, June 2008
[15] "Measures and Assumptions for Demand Side Management (DSM) Planning", Navigant Consulting, April 16, 2009

- Secondary Schools
- Large Commercial/Retail buildings

Please refer to Appendix D for a detailed program description.

Projected Outcome:

In the short to medium terms, the efficient water heater program is not expected to provide results similar to those realised by the boiler programs. Table 5-10 provides program highlights of the Efficient Water Heater Program forecasted performance metrics for 2010.

Table 5-10: Modest initial TRC performance in the program's first year

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	TGI	25	62	17	2,185	18,932	5%	1.1
	TGVI	3	7	5	262	2,261	5%	1.0
Retrofit	TGI	60	149	41	5,244	45,436	5%	1.1
	TGVI	6	15	10	524	4,523	5%	1.0

The performance of the program in its introductory year is expected to be modest. TRC's and program participation rates should remain relatively low while spending on promotions will be high in view of raising awareness. Vancouver Island is expected to see low participation, given TGVI's experience with its current incentive programs; the island generally lags behind the mainland in terms of participation on a per capita basis. The profile of the EEC programs needs to be raised on the island. Sustained promotional efforts in conjunction with the Efficiency Partners Program are expected to significantly redress this situation moving forward.

Also minimizing initial effectiveness is the reality that high efficiency technology is relatively new to domestic hot water heating, and as such the incremental price difference remains high. The cost to benefit ratio is therefore adversely impacted from the outset. As the incremental cost of the technology is reduced over time this situation will be improved. Furthermore, participation in the program is expected to be more limited than in the boiler programs, as only participants with high hot water requirements (as outlined above) are expected to obtain a reasonable payback by using high efficiency hot water heaters.

For cost benefit analysis please refer to Appendix J.

Summary:

As the market place becomes more aware of the program it is expected that increased participation will lead to improved performance in 2011. The program's simple structure should, similar to the Light Commercial ENERGY STAR® Boiler Program, help to keep administrative spending low over the long run and also contribute to a solid TRC showing.

5.6.2.4 Energy Assessment Program

Program Area: Commercial Energy Efficiency Programs

Target Market: Retrofit

Duration: TGI: 2001 – December 31, 2011
TGVI: 2001 – December 31, 2011

Program Updates for 2010:

The program will see several changes in 2010 aimed at improving its performance. Changes will include:

1. Requiring participants to pay for 50% of the assessment initially. The remaining 50% will be reimbursed once a participant has implemented all identified energy savings measures with a payback period of less than 2 years.

2. Developing a formalized energy savings tracking methodology.

3. Remarketing and promoting the program so as not to conflict with the Custom Design Program (refer to Section 5.13.6.2 Custom Design Pilot Program for a description of this program) and to ensure that participants in the program are those for whom a simple energy assessment as opposed to a full energy audit will suffice.

As the Companies continue to develop additional Energy Efficiency incentive programs, the Energy Assessment program risks coming into conflict with those programs when claiming GJ savings. As such, the Companies are considering restructuring the Energy Assessment Program as an enabling activity whose costs may be accounted for in the overall Commercial Energy Efficiency Program TRC.

Background:

As discussed in Section 4.4.5, the Energy Assessment Program is designed to identify inefficiencies in natural gas energy consumption and provide recommended solutions to commercial customers who consume more than 2000 GJ per year. The Companies strongly believe that an Energy Assessment program is essential to:

1. Reaching out to and engaging commercial customers on matters of energy efficiency.

2. Fostering a culture of conservation within the commercial sector in the province.

Please refer to Appendix D for a detailed program description.

Projected Outcome:

The Energy Assessment Program will be modified in late 2010 to improve its effectiveness in terms of GJ's saved per dollar spent, at reducing commercial sector gas consumption. In the meantime TGI and TGVI will run the program as is, though promotion of the program will be limited and its performance is expected to be impacted as a result.

Table 5-11 provides program highlights of the Energy Assessment Program performance metrics for 2010 based on our forecast.

For cost benefit analysis please refer to Appendix J.

Table 5-11: Energy Assessment Program Performance Metrics

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	TGI	45	54	16	12,110	22,087	10%	2.6
	TGVI	5	6	4	1,346	2,451	10%	2.1

The Companies are currently engaged in a second evaluation study of the program (an initial study was completed in 2008) based on participation from July 2007 through July 2009. This study will provide additional needed insight into the program's performance and allow the Companies to confirm the data underlying the performance results presented above. Furthermore the evaluation study will provide additional insight into where the program may be modified to enhance its performance. Refer to Section 5.13.3.3 for details on the Energy Assessment Program Evaluation.

5.6.2.5 Process Heat Program (Under Development)

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: To be determined
TGVI: To be determined

Program Objectives:

- Reduce gas consumption among manufacturing / light industrial customers by encouraging the installation and use of high as opposed to standard efficiency water appliances in manufacturing processes.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate manufacturing / light industrial customers about the advantages of reducing gas consumption and provide an incentive to facilitate the purchase of high efficiency technology.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.

Background:

The Process Heat program will capture gas savings by directly addressing inefficient equipment or operations in manufacturing processes. This may include items such as old boilers, piping insulation, process controls, etc. Target participants will include organizations in agriculture, food processing and manufacturing such as asphalt production. The program is likely to include a capital cost incentive and may include an additional monitoring and performance incentive.

5.6.2.6 Commercial Cooking Program (Under Development)

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: To be determined
TGVI: To be determined

Program Objectives:

- Reduce gas consumption in commercial cooking operations by encouraging the installation and use of high as opposed to standard efficiency cooking appliances.
- Increase year over year participation rates in view of maximizing gas savings and bringing about market transformation.
- Educate commercial kitchen customers about the advantages of reducing gas consumption and provide an incentive to facilitate the purchase of high efficiency technology.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
- Prepare the way for and support any provincial regulation requiring increased commercial cooking appliance efficiency.

Background:

According to the 2006 CPR, commercial cooking represents the third most important consumer of gas in British Columbia's commercial sector gas users. The Commercial Cooking program will capture gas savings by encouraging the use of high efficiency (generally ENERGY STAR® rated) cooking appliances in commercial kitchens. Typical appliances include fryers, ovens, boilers, steamers and ranges. Target participants will include restaurants, health care, care homes, education and institutional organizations. The program will likely be delivered in the form of an appliance purchase rebate.

5.6.2.7 Commissioning Program (Under Development)

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: To be determined
TGVI: To be determined

Program Objectives:

- Reduce gas consumption among the commercial sector's existing building stock by providing an incentive to help commercial customers maximize their facilities operating performance.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate commercial sector customers about the impacts of poorly maintained / operated building systems and provide an incentive to facilitate both the maintenance of existing equipment, as well as the implementation of proper operating strategies.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.

Background:

Studies indicate that building commissioning, especially of existing buildings, represents one of the most cost effective sources of energy savings and GHG reductions. The Commissioning program will capture gas savings by ensuring that participating facilities / buildings are operated in the most efficient and effective manner possible.

Target participants will generally include government, medium to large commercial, large multi-residential, health care, education and institutional organizations. The program will likely be delivered in the form of a performance based incentive, wherein participants will be given a certain dollar amount per GJ actually saved.

The Companies are working to partner with BC Hydro on its currently operating commissioning program known as the Continuous Optimization program. If the TRC tests are positive, the Companies will begin paying for the gas side measures required to operate the program and subsequently claim the GJ savings.

5.6.2.8 Victoria Spray Saver Program (Under Development)

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI: Not Available
TGVI: May through August 2010

Program Objectives:

- Reduce gas consumption in associated with dishwashing by installing low flow pre rinse spray valves in food service establishments.
- Install new low-flow pre-rinse spray valves in approximately 300 locations in the greater Victoria area.
- Maintain a program TRC greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.

Background:

The Companies are planning to run another Spray Saver program in 2010 in conjunction with BC Hydro. The program will focus on the greater Victoria region and, similar to the Okanagan program, will seek to achieve a reduction in natural gas consumption associated with the production of hot water by reducing hot water use in commercial kitchens. TGVI will install, free of charge, new low-flow pre-rinse spray valves in willing food service facilities (i.e. restaurants, coffee shops, delis, groceries, etc.) in order to reduce the volume of hot water used in dishwashing.

5.6.3 Summary

The Companies intend to broaden their commitment to Commercial Energy Efficiency programs in 2010.

Existing programs such as the Efficient Boiler Program, Light Commercial ENERGY STAR® Boiler Program, and the Energy Assessment Program will each be refined and continued.

Where market research suggests it will create value to do so, the Companies will also roll out new programs to increase the Portfolio's impact in the Commercial space. These new programs include the Efficient Water Heater Program, Commercial Cooking Program, the Commissioning Program, and the Process Heat Program.

Collectively this portfolio will continue to create value in 2010 with the important stakeholder group of Commercial customers while laying a foundation for continued EEC efforts in 2011 and beyond.

5.7 High Carbon Fuel Switching

High Carbon Fuel Switching program initiatives are designed to result in lower overall GHGs by using natural gas in place of higher carbon fuels such as coal, oil or propane. In addition, further GJ savings will be recovered by replacing older less efficient high-carbon appliances with high efficiency natural gas appliances such as ENERGY STAR® furnaces or boilers.

5.7.1 Residential Retrofit Program Focus for Portfolio in 2010

The first program is a residential retrofit program, focused on converting oil or propane heating systems to ENERGY STAR® natural gas appliances. This program, the Switch 'N' Shrink Program, is described below.

As 2010 progresses, other programs still at the initial concept stage will be evaluated for inclusion in this Program Area.

5.7.1.1 Switch 'N' Shrink Program

Program Area: High Carbon Fuel Switching

Market: Retrofit

Duration: January 1, 2010 to December 31, 2010 with possible extension

Incentive: $1000 rebate cheque for oil or propane conversion

$50 rebate cheque for Electronically Commutated Motors ("ECM") from BCHydro or FortisBC

Partners: BCHydro and FortisBC

Program Administration:

Consumer Response Marketing

Program Objectives:

The program is designed to achieve the following:

- Provide a $1000 incentive to encourage homeowners to convert their primary heating system from higher carbon oil or propane to a high efficiency natural gas heating system
- Upgrade a minimum of 750 homes
- Develop relationships with associations for co-marketing opportunities, for example BC Insurance Brokers Association, real estate associations, environmental groups
- Work with MEMPR to include this program as part of the provincial greenhouse gas reduction strategy
- Develop a cost effective program with TRC greater than 1.0 that achieves significant energy savings, cost savings and greenhouse gas reduction benefits

Background:

A 2005 Statistics Canada Victoria market report indicated that 21% of the households still used oil (19% natural gas) and represented 29,000 oil customers. This market potential demonstrates the huge opportunity to reduce GHG's through natural gas conversions.

The Switch 'N' Shrink Program offers participants a $1000 rebate for converting their primary home heating system (furnace or boiler) from higher carbon oil or propane to an ENERGY STAR® natural gas heating system. The participant lowers their energy bills, increases their property value, reduces the potential of an environmental hazard, and shrinks their carbon footprint.

The program is available to all new and existing customers (where primary heating source is oil or propane) in all of the Companies' service areas except Whistler, beginning January 1, 2010.

ENERGY STAR® heating systems installed with an ECM are eligible for an additional $50 incentive funded by BC Hydro and FortisBC.

The program is offered to all BC residents, however almost 70% of the 1233 conversions in 2009 were on Vancouver Island, where the use of oil is more prevalent than in the rest of the Companies' service territory. Homes near a gas main are more likely to participate, however all potential customers may want to take advantage of this program. On-Main Market potential for TGVI oil and propane conversions is difficult to estimate, but could range from 20,000 to 40,000 households.

Please refer to Appendix D for a detailed program description.

Projected Outcome:

The program will deliver significant energy, cost, and GHG benefits through 750 conversions. Table 5-12 provides program highlights of the projected Switch 'N' Shrink Program performance metrics for 2010.

Table 5-12: Switch 'N' Shrink Program Performance Forecast illustrating the effective cost benefit tests associated with the Switch 'N' Shrink program

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)*	NPV Energy Savings (GJ)*	Free Rider Rate	TRC
TGI	225	225	25	(4,838)	(50,954)	50%	1.6
TGVI	525	525	200	(11,288)	(118,191)	50%	1.4
Total	750	750	225	(16,125)	(169,145)	50%	1.5

* Note: Energy savings in a fuel switching program are negative since this is a load building program from higher carbon fuel sources (oil and propane) to lower carbon natural gas.

The overall program benefits are captured by avoiding higher carbon fuel costs while incurring lower natural gas fuel costs for an overall reduction in net GHG emissions. The net benefit for the participant is in reduced energy costs while helping BC meet its provincial GHG reduction targets. From a Utility standpoint, the benefit is in adding more customers to the distribution system, especially where a gas service already exists in close proximity, keeping the overall system costs per customer down. Table 5-13 illustrates these points and the significant energy, cost and GHG savings that are obtained based on 750 furnaces converted from oil to natural gas.

Table 5-13: Switch 'N' Shrink Program Benefits analysis illustrating significant energy, cost, and GHG benefits per 750 conversions

Utility	NPV Natural Gas Incurred (GJ)	NPV Oil Displaced (GJ)	NPV Energy Savings (GJ)	NPV Costs to Purchase Natural Gas ($000s)	NPV Costs to Purchase Oil ($000s)*	NPV Cost Savings upon Conversion ($000s)	GHG Savings (tCO2e)
TGI	50,954	56,033	5,079	540	1,226	687	1,375
TGVI	118,191	130,743	12,552	1,259	2,845	1,586	3,242
Total	**169,145**	**186,776**	**17,631**	**1,799**	**4,071**	**2,273**	**4,617**

* Note: Source of Energy prices –November, 2009 http://www.mjervin.com/index_PetroleumPrices.htm where Oil = $22.50 / GJ

The oil to natural gas conversion overall program benefits are significant when considering the energy savings over the lifetime of the measure. Significant benefits per 750 conversions include the following:

- 17,631 net GJ's of energy saved
- $2.27 Million in net cost savings
- 4,617 net tCO2e

The program performance estimate of 750 participants is likely conservative based on initial interest from contractors, as well as considerable interest from the BC Interior region for conversion projects. Incentive dollars are forecasted at $750,000 while total spend for non-incentive dollars is estimated at $225,000. The $1000 incentive is meant to cover the incremental cost of upgrading to a natural gas furnace, rather than replacing an existing oil furnace with another oil furnace. Non-incentive spending represents only 30% of total spend.

The 50% Free Rider Rate was based on the assumption that half of the program participants would convert because of the incentive and the other half would have converted regardless of the program. This Free Rider Rate is in alignment with the 43% Free Rider Rate used in the ENERGY STAR® Heating System Upgrade Program. The overall TRC for this program is 1.5.

Please refer to Appendix D for a detailed program description.

<u>Summary</u>

The High Carbon Fuel Switching Program Area, within which Switch 'N' Save is the first program to market, will result in significant energy, dollars, and GHG savings over time. For every 750 oil-to-efficient natural gas conversions, fossil fuel consumption is reduced by 17,631 GJ's of energy, approximately $2.2 Million is saved by customers, and 4617 tons of GHG's are reduced. High carbon fuel switching program initiatives, such as the Switch 'N' Shrink program, will provide significant benefits to the Province of BC's GHG reduction strategy.

5.8 Conservation for Affordable Housing Programs

The first of the EEC Program Principles is that, “Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative.”

The Companies are staying true to this principle by developing and implementing programs that are of no cost or low cost to low-income participants. Further, the DSM Regulation states that a (public) utilities’ portfolio is adequate only if it provides (amongst other things) measures specifically intended to assist residents of low-income households and those living in rental accommodations to reduce their energy consumption.[16]

The Companies believe firmly in these guiding principles, and their commitment to them is reflected in the Conservation for Affordable Housing Programs they will implement in 2010.

5.8.1 Program Portfolio Overview

The 2010 Conservation for Affordable Housing Portfolio consists of two program categories: studies and programs aimed at low-income individuals and renters. The initiatives discussed in this section satisfy the requirements in clauses 3(a) and 3 (b) of the DSM Regulations for measures aimed at residents of low-income households and rental accommodations.

Table 5-14 provides a summary of the 2010 Conservation for Affordable Housing program’s initiatives.

Table 5-14: 2010 Conservation for Affordable Housing Programs Initiatives

	Project	Description	Retrofit		
			Incentive & Non-Incentive Expenditure ($000s)	NPV Energy Savings (GJ)	TRC
1	BC Affordable Energy Conservation Strategy (study)	A province-wide strategy paper for addressing conservation for affordable housing.	50	N/A	N/A
2	Strategic Energy Management Plan (study)	A study focused specifically on the non-profit housing sector in BC.	18	N/A	N/A
3	CHF BC Energy Performance Housing Inventory (study)	A building inventory of co-operative housing in BC.	15	N/A	N/A
4	REnEW	Capacity building program focused on increasing the supply of energy efficiency assessors and installers	258	N/A	N/A
5	Energy Savings Kits (ESK)	Partnership with BC Hydro for self-install energy efficiency measures	349	30,193	1.2
6	Energy Conservation Assistance Program*	Partnership with BC Hydro for direct-install energy efficiency measures	3,130	307,662	1.0

* The Companies plan to use $1.5 million of the MEMPR Low Income Partnership funds to contribute to BC Hydro through our ECAP partnership. The remaining budget for ECAP and all the remaining investments shown above are EEC investments in the Conservation for Affordable Housing program area. Only EEC investments will be included in the overall portfolio level TRC calculation.
Note: As per DSM regulation, the TRC caluculation for all low income programs applies a deemed benefit of 130% of what the benefit would recognized as in an able-to-pay program's TRC calculation. This regulation is applied in the TRC figures shown above.

[16] See Appendix B, Demand Side Measures Regulation, November 7, 2008, Section 3 (b).

5.8.2 Committed to Developing Expertise Through Research

The first component of the Conservation for Affordable Housing Program Area is a set of studies the Companies will participate in during 2010. Through these studies, TGI and TGVI will gain expertise in and insight into this market segment and its unique requirements.

There are three studies related to Conservation for Affordable Housing that the Companies are already planning to be involved in during 2010.

5.8.2.1 BC Affordable Energy Conservation Strategy Paper

The Affordable Energy Conservation Strategy Paper ("Strategy Paper") is being developed (through research and a consultation process) to provide recommendations that ensure that low income homes can actively participate in and benefit from targeted energy efficiency programs in this province.

The Companies are facilitating the Working Group and Task Force which is overseeing the development of this Strategy Paper. Currently, the Strategy Paper is in the research phase which is expected to be completed by the end of March. The research is focused on the current challenges, opportunities and best practices relating to energy efficiency programs for low income individuals and is being completed by a University of Victoria Environmental Law Centre student.

Following the research, the Task Force will identify what areas of research are still lacking and undergo a consultation process in order to address the gaps identified in the research. The research outcomes and the plan for consultation process will be shared with the Working Group at the next Working Group meeting in May, 2010. It is expected that the strategy paper will be developed by the end of 2010.

5.8.2.2 Strategic Energy Management Plan Study ("SEMP")

The second study that the Companies are supporting is the Strategic Energy Management Plan ("SEMP"). This study is commissioned by the Companies and BC Hydro and will be performed by City Green Solutions and the BC Non-Profit Housing Association. The study is specifically focused on the non-profit housing sector and seeks to match energy consumption information with building characteristics in order to prioritize energy efficiency investments. This study will be completed by Q3 2010.

5.8.2.3 Co-Operative Housing Federation – BC Energy Performance Housing Inventory

The third study is the Co-operative Housing Federation's ("CHF") BC Energy Performance Housing Inventory which is a first step towards addressing the complex nature of working with Co-operative Housing. This step will allow CHF BC to gain a better understanding of their housing stock. This is modelled on the success of BC Non-Profit Housing Association's Asset Analysis study. This inventory will allow for a strategic approach to be designed that will ultimately allow for the prioritization of energy retrofits in Co-ops in BC. This study will be commissioned by the Companies, BC Hydro and BC Housing and will be performed by City Green and eaga Canada Ltd.

5.8.2.4 Additional Studies

The above studies are presently the only three planned for 2010. However, there may be other opportunities in 2010 for further studies and those opportunities will be assessed as they arise.

5.8.3 Conservation for Affordable Housing Programs

The second component of the Portfolio is a collection of tactical programs. These have been developed by the Companies in partnership with electric utilities.

The Companies have developed and launched an Energy Efficiency Training Program titled, Residential Energy and Efficiency Works ("REnEW"). The Companies have also made progress towards the implementation of an Energy Savings Kit, and integration into the Energy Conservation Assistance Program. As well, initial concepts have been developed to further invest some of the MEMPR Low Income Partnership Funding.

These programs are described in detail below.

5.8.3.1 REnEW, Residential Energy and Efficiency Works

Program Area: Conservation for Affordable Housing Programs

Target Market: Retrofit

Duration: February, 2010 to December, 2011

Incentive: The Companies will contribute approximately $257,500 per year.

Funding Partners:

- FortisBC
- BC Hydro
- Ministry of Advanced Education and Labour Market Development

Delivery Partners:

- The Companies are the lead developer and administrator for this program. Other contributors and delivery partners include:
    - BladeRunners
    - Aboriginal Community Career Employment Services Society ("ACCESS")
    - John Howard Society, Central and South Okanagan
    - Southern Interior Construction Association

Program Objectives:

- Enhance and expand the energy efficiency retrofit industry
- Add energy-efficiency-focused capacity to delivery agents that work within low-income sectors
- Increase the quality of energy efficiency retrofitting installations through training

- In the long term, by increasing the supply of skilled energy efficiency workers, utilities will be able to implement energy efficiency retrofits at lower costs.

Background:

The Companies are leading a capacity-building program aimed at increasing the supply of qualified energy assessors and installers. This energy-efficiency focused training has been developed by the Companies, John Howard Society, Bladerunners, the Southern Interior Construction Association, FortisBC and BC Hydro. By facilitating this training course and increasing the supply of workers skilled in energy efficiency retrofitting, the Companies believe that the delivery costs of DSM programs that involve retrofitting will be decreased, and our ability to implement programs in remote communities will be enhanced.

The training program has been initially designed for, and targeted to, the clientele of the John Howard Society in Kelowna, and BladeRunners in the Lower Mainland. John Howard Society's clientele is primarily those who have had contact with the justice system. BladeRunners works with Inner City disadvantaged 'street-involved' youth. The Companies intend to offer the course a total of 5 times in 2010 and will include at least one Vancouver Island course offering.

Given the clientele that the Companies are seeking to assist through this initiative, the training will not require any prerequisite qualifications other than the desire to pursue work in the energy efficiency industry. Training will be 4-5 weeks and includes classroom time and in-the-field, hands-on experience. The training will cover a breadth of content including general energy conservation education, an understanding of energy as a resource, concepts such as 'house as a system', as well as the application and installation of energy efficiency measures. In addition to the energy-related education, the program includes general construction trade training and highly desired certifications such as WHMIS, First Aid, and Construction Safety Training System. The program is primarily focused on the energy efficiency industry and prepares graduates for employment relating to utilities' direct-install DSM programs. The training also opens the door to further formal training such as certified energy advisors.

Projected Costs:

The average estimated cost per course in-take is based on costs associated with the first two in-takes. The cost estimate of $103,000 includes the costs of trainers, course development costs, food for participants during the course, a full set of tools for the participants, and overhead costs of program delivery agents.

Table 5-15 shows estimates of costs associated with offering this program.

Table 5-15: REnEW Program Cost Estimates

Utility cost per in-take	$ 103,000
Number of in-takes	5
Total Annual Utility Costs	**$ 515,000**
BC Hydro and/or Fortis BC Annual Contributions	$ 257,500
The Companies Annual Contribution	$ 257,500

As the program is expanded to other parts of our service territory the Companies will look for additional funding partners.

5.8.3.2 Energy Savings Kits ("ESK")

Program Area: Conservation for Affordable Housing Programs

Target Market: Retrofit

Duration: May, 2010 to December, 2011

Incentive: The Companies will contribute approximately $13.76 per ESK

Partners:

- FortisBC
- BC Hydro

Program Objectives:

- Enable over 11,000 low-income participants to self-install energy efficiency measures in their homes.
- Make energy efficiency more accessible to low-income customers by addressing the key barriers to energy efficiency in this sector (including affordability, availability and awareness)
- Provide energy savings for TGI/TGVI
- Provide low-income customers with the opportunity to reduce their energy consumption which will also reduce their energy bills and GHG emissions.
- Create a culture of conservation through increased knowledge and awareness of conservation behaviours.

Background:

ESK is a self-installed kit of energy saving measures. BC Hydro and FortisBC have ESK's already available to their low-income electricity customers. The intention is to partner with BC Hydro and FortisBC in order to simplify the process for shared customers and reduce administration and marketing costs.

With the Companies' involvement in this project the ESK offer will become a broadly marketed and easily accessed program available to customers in all three utility partners' regions, regardless of their fuel type. Participants will be able to call a toll-free number, or visit a website to apply for the program. Based on the approval of a customer's application, instructions will be sent to a supplier to send out the kit. The only eligibility criteria will be that the participant is a low income customer of any of the three utilities. The definition of "low income customer" for this program is based upon Statistics Canada Low Income Cutoff ("LICO").

The intention is to have the application process and the packaging of the ESK jointly branded so that the customer will have a seamless experience from the time they hear about the ESK offer to the time it is delivered to their home. The kit will be delivered at no cost to the participants and will include several easy to install energy savings measures, such as water heater pipe wraps, low flow shower heads, faucet aerators, weather stripping, foam tape for door insulation, and other measures. The ESK will also include educational brochures that will help customers reduce their energy consumption through simple behavioural changes.

The intention is to have the kits available by May 2010.

Projected Outcome:

The incentive amount of $162,000 (for both TGI and TGVI) is the estimated cost of the ESK including packaging and delivery. The Energy Savings NPV of 30,193 GJs is based on achieving an aggressive goal of sending 11,000 ESKs to customers in 2010. The resulting TRC is 1.2.

Table 5-16 describes estimated performance and investments in the ESK.

Table 5-16: ESK Program Estimates

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	9,000	130	150	3,947	24,155	8%	1.2
TGVI	2,000	32	37	987	6,038	8%	1.2

Note: As per DSM regulation, the TRC caluculation for all low income programs applies a deemed benefit of 130% of what the benefit would recognized as in an able-to-pay program's TRC calculation. This regulation is applied in the TRC figures shown above.

5.8.3.3 Energy Conservation Assistance Program ("ECAP")

Program Area: Conservation for Affordable Housing Programs

Target Market: Retrofit

Duration: June, 2010 to December, 2011

Incentive: The Companies will contribute approximately $850 per participant.

Partner: BC Hydro

Program Objectives:

- Enable over 3,000 low-income participants to receive comprehensive energy evaluations in their homes and have a suite of energy efficiency measures installed for them.

- Make energy efficiency more accessible to low-income customers by addressing the key barriers to energy efficiency in this sector (including affordability, availability and awareness)
- Provide energy savings for TGI/TGVI
- Provide low-income customers with the opportunity to reduce their energy consumption which will also reduce their energy bills and GHG emissions.
- Create a culture of conservation through increased knowledge and awareness of conservation behaviours.
- Leverage the graduates of the REnEW program to perform retrofits in qualified customers homes.

Background:

The Energy Conservation Assistance Program ("ECAP") is a targeted program that, in its current state, is only offered by BC Hydro to low income high electricity users. The Companies intend to participate in this program and broaden its reach and impact to include low income natural gas users.

Presently prospects are identified through social housing providers, program delivery agents and targeted communications. Recipients of the Energy Savings Kits are also prospects for participation in this program if they meet the minimum energy consumption criteria. The program involves assessments of energy savings opportunities, and installation of energy efficiency measures, which currently include items such as attic insulation, crawl space insulation and draft proofing.

With the Companies' involvement in this program, the target will be expanded to include all high energy users regardless of their home heating fuel source.

Projected Outcome:

This initiative is in its very early stages of development, and budgeted amounts may vary significantly from the early estimates provided in Table 5-17. The intention is to have the program available to gas customers by the end of Q2, 2010.

Table 5-17: ECAP Early Budget Estimates

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
TGI	2,600	2,200	304	25,955	246,130	4%	1.0
TGVI	650	550	76	6,489	61,532	4%	1.0

As per DSM regulation, the TRC caluculation for all low income programs applies a deemed benefit of 130% of what the benefit would recognized as in an able-to-pay program's TRC calculation. This regulation is applied in the TRC figures shown above.

The incentive amount of $2,750,000 (for both TGI and TGVI) is based on an average of just under $850 per participant. The Energy Savings NPV of 307,662 GJ is based on achieving an aggressive goal of 3,250 participants in 2010. The resulting TRC is 1.0.

5.8.3.4 MEMPR Low Income Partnership Funding

As discussed in Section 4.5.3, on March 31, 2009, MEMPR awarded TGI and TGVI a grant of $5.155 million to support and develop programs for low-income individuals in British Columbia. This agreement stipulated that $1.5 million is to be contributed to projects with BC Housing, $1.5 million for projects with BC Hydro, and $2.155 million allocated for the development of additional TGI and TGVI programs for low-income participants. This funding is to be invested by March 31, 2012.

The $1.5 million that was stipulated to go to BC Housing has since had $1 million re-allocated at the request of MEMPR to go towards the Super Efficient New Construction ("SENC") program for superior energy performance in new construction projects that house low-income occupants. The SENC Program Oversight and Evaluation Committee chaired by MEMPR and including representatives from the Companies, MEMPR, BC Hydro and FortisBC selected six projects, and intend to have the contracts finalized and signed with individual construction project proponents by April 30, 2010. Table 5-18 below includes the selected projects.

Table 5-18: Super Efficient New Construction

	Project	Funding Request in Submission	Total Funding by SENC
1	Elizabeth Fry Society Transition House for Women and Children	$500,000	$222,000
2	Union Street EcoHeritage Project	$269,000	$125,000
3	Educational / Commercial Affordable Housing Project	$250,000	$200,000
4	Ucluelet Passive House	Unclear From Proposal	$75,000
5	CRD Affordable Housing Project	$500,000	$278,000
6	Dawson Green	$180,000	$100,000
	Total		**$1,000,000**

The remaining $500,000 was allocated to the $2.155 million for the development of additional TGI and TGVI programs for low-income participants.

The $1.5 million for projects with BC Hydro is stipulated to go towards comprehensive retrofits of 750 natural gas heated homes in partnership with BC Hydro's low income programs. Specifically, the Companies intention is to apply this $1.5 million to a partnership on BC Hydro's ECAP program described above. The estimated investments in the ECAP program is well above $1.5 million and the remaining investment will come from the EEC approved funding for Conservation for Affordable Housing.

A portion ($965,803) of the $2.655 million stipulated for TGI and TGVI programs for low-income participants has been used to fund retrofits under the LiveSmart Carry Over project described in Section 4.5.3. The remaining $1.689 million will go towards additional TGI and TGVI programs that have not yet been developed, but that may include a partnership with FortisBC to fund the energy efficiency retrofits in four buildings in Kelowna where John Howard Society clients live.

5.8.4 Summary

The Companies are committed to developing and implementing programs that are of no cost or low cost to low-income participants. Further to this commitment, the Companies will participate in at least three studies in 2010 to gain further insight into the unique needs of this market segment. The Companies will also introduce a series of programs developed in partnership with electric utilities – an Energy Efficiency Training Program (REnEW), an Energy Savings Kit, and integration into the Energy Conservation Assistance Program.

These initiatives will promote conservation attitudes and create value through savings in a market segment that needs to be included in EEC programming. The programs described in this section satisfy the plan portfolio adequacy requirements in the DSM Regulation for energy savings measures for residents of low income housing.

5.9 Joint Initiatives For Energy Efficiency Programs

In 2010, the Companies will continue to participate in mutually beneficial collaborations between groups such as government agencies or BC utility partners. Please refer to Section 4.6 for more background on Joint Initiative projects.

5.9.1 Joint Initiative Program Portfolio

In 2010 the Companies will continue to carry out the EcoEnergy Home Assessment (in partnership with LiveSmart BC) while developing and rolling out new Joint Initiatives.

Joint Initiatives programs for 2010 include the EcoEnergy Home Assessments with LiveSmart BC, BC Hydro and FortisBC that will end March 31, 2010. Utility Partners are collaborating on developing a program for energy efficient home retrofits for the able-to-pay sector (as opposed to the Affordable Housing sector discussed above). Other programs under consideration include appliance rebates with FortisBC, and working with BC Hydro to fund Energy Specialists to complement BC Hydro's Energy Manager Initiative.

Table 5-19 provides a summary of the 2010 Joint Initiatives.

Table 5-19: 2010 Joint Initiatives Energy Efficiency Programs are currently under development with Utility Partners and government to provide energy savings programs and outreach across the province

	Program	Description	New Construction		Retrofit		TRC	
			Incentive & Non-Incentive Expenditure	NPV Energy Savings	Incentive & Non-Incentive Expenditure	NPV Energy Savings	TGI	TGVI
1	EcoEnergy Home Energy Assessments (D-Visits) through LiveSmart BC	$75 Incentive to cover the partial cost of Home Energy Assessment provided by an NRCan certified Home Energy Advisor	N/A		717	0	N/A	N/A
2	Utility Partner Collaboration - Home Renovation Project	TGI, TGVI, BCH, FortisBC and MEMPR in discussions.	N/A		Under Development			
3	Energy and Water Efficient Appliance Programs	Work with FortisBC to provide incentives for energy and water efficient appliances	N/A		Under Development			
4	Energy Specialists	Provide funding for Energy specialist focused on natural gas savings to complement BCHydro's Energy Manager	N/A		Under Development			

The highlights of the 2010 existing Joint Initiatives programs are as follows:

- EcoEnergy Home Assessment funding, provided through a partnership with LiveSmart BC, demonstrates the Companies' support for energy assessments as a critical first step in the retrofit process and "whole home" incentives. From August 16, 2009 to March 31, 2010 the Companies expect to provide funding for 15,000 assessments with a contribution of $1.125 Million.

The highlights of the new 2010 Joint Initiatives programs are as follows:

- Utility Partners have been collaborating to develop a program for energy efficient home retrofits. The Companies are working with utility partners and MEMPR to define roles and determine how each party will contribute to delivering a successful program to customers.

- TGI is working with FortisBC on programs for energy and hot water efficient appliance rebates. TGI's participation extended the program reach to natural gas water heating customers and those with gas dryers.

- The Companies are in discussion with BC Hydro about providing funding for an Energy Specialist that would be put in place to complement the BC Hydro Energy Manager program. Through utility collaboration, large commercial and institutional entities, municipalities, universities, school districts, health regions and industry associations could access expertise to reduce energy (both electric and natural gas) and save money.

The Joint Initiatives programs for 2010 are described in further detail below.

5.9.1.1 EcoEnergy Home Assessment (D-Visit Audit) Support Through LiveSmart BC

Program Area: Joint Initiatives

Target Market: Retrofit

Duration: August 16, 2009 through March 31, 2010

Incentive: $75 subsidy from Utility Partner (based on fuel source) and $75 from MEMPR

Partners: TGI, TGVI, BC Hydro, FortisBC and MEMPR

Program Administration:

LiveSmart BC

Program Objectives:

- Provide incentives for Home Energy Assessments as the first step in improving the energy efficiency of existing building stock
- Support LiveSmart BC in the interim funding period prior to new program iteration in April, 2010

Background:

Please refer to Section 4.6.2.1 for more information about this program

Projected Outcome:

Table 5-20 provides program highlights of the EcoEnergy Home Assessments Program estimated performance metrics for 2010.

Table 5-20: EcoEnergy Home Assessments Participant Numbers and Contribution

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)
Invoiced: Aug 16 - Dec 31, 2009	TGI	5,182	389	16
	TGVI	263	20	4
Estimates: Jan 1 - Mar 31, 2010	TGI	7,644	573	-
	TGVI	1,911	143	-
Total	TGI	12,826	962	16
	TGVI	2,174	163	4
Program Total Estimates *		15,000	1,125	20

* program estimates from MEMPR based on NRCan D- visit data

Recognizing the importance of the home energy assessment as the first step in energy efficient retrofits, the Companies anticipate subsidizing a total of 15,000 assessments for a contribution $1.125 million from August 16, 2009 through March 31, 2010, which is the provincial fiscal year end. Due to the nature of this project, in that the assessment is an evaluation step only, the Companies recognize that no energy savings can be claimed directly as a result of this program. Rather, the Home Energy Assessment is an avenue into other retrofit incentives that result in energy savings.

5.9.1.2 Utility Partner and LiveSmartBC - Home Renovation Program (Under Development)

Program Area: Joint Initiatives

Target Market: Retrofit

Duration: To be determined

Offer: Final offer to be determined

Partners: TGI, TGVI, BC Hydro, FortisBC, NRCan, and MEMPR

Background:

The Companies are working with BC Hydro and FortisBC to establish a Utility Partner collaboration model for a BC Home Renovation program. The primary objective of the collaboration is to develop a platform that is sustainable and can remain in the market for many years without relying on the contribution of any one partner. The Utility Partners support the "whole home" or "house as a system" approach to energy savings, and in parallel to consumer incentives the Utility Partners will develop a longer term vision to jointly fund education and outreach, working to engage consumers and the trades in energy efficient retrofits.

This Joint Initiative between Terasen Gas, BC Hydro and Fortis BC is in the design stage and the structure of the program is subject to change. The Utility Partners remain committed to working together with other stakeholders to bring a sustainable home renovation program to the province of BC.

5.9.1.3 Water and Energy Efficient Appliance Programs (Under Development)

During the summer of 2009, the Companies partnered with FortisBC on a six week pilot to promote energy and water savings by providing $50 incentives to customers in their service territory who purchased a Tier 3 ENERGY STAR® Washer or Dryer. An expanded program is being planned for 2010 in the FortisBC service territory. Working with other utilities will leverage administrative processes, reduce costs and increase program participation by sharing marketing channels.

5.9.1.4 5.9.5 Energy Specialist Program with BC Hydro (Under Development)

The Companies are working with BC Hydro to provide funding for an Energy Specialist that would be put in place to complement the BC Hydro Energy Manager program.

There are a number of large commercial and institutional entities, municipalities, universities, school districts, health regions and industry associations where BC Hydro funds the activities of an Energy Manager, who is charged with uncovering opportunities for energy savings projects. The Companies will fund the activities of an Energy Specialist, for mutual customers where a BC Hydro Energy Manager is in place, who would complement the activities of the Energy Manager by focussing on natural gas savings opportunities. Due to the early development stage for this program, no budget had yet been set at the time of writing.

This would bring a more complete approach to energy savings projects for large commercial and institutional entities, municipalities, universities, school districts, health regions and industry associations in British Columbia.

5.9.2 Summary

Joint Initiatives provide numerous mutually beneficial advantages for the Companies' energy efficiency programs. In working together, utilities and government partners can extend the reach of incentives, provide cost effective education and outreach, and generate significant savings and greenhouse gas reductions.

5.10 Conservation, Education and Outreach ("CEO") Programs

As described in Section 4.7, the objective of CEO initiatives is to support the development of a conservation culture within British Columbia. CEO activities help to ensure that customers are aware of and will be receptive to incentive programs when they are proposed.

Crucial to the success of EEC programs is creating and promoting awareness of conservation in general which generates desire by participants to engage in EEC activities. The CEO objectives ultimately lead to the success of the individual programs and support the energy conservation and GHG reduction goals established by the Government of BC.

5.10.1 Guiding Principles Remain in Place

The CEO programs are intended to allow engagement and opportunities for participation by all customer sectors. As with the CEO activity in 2009, the CEO activity for 2010 will follow many of the same Program Principles that were put forth in the EEC Application, in particular:

1. Programs will have a goal of universality; offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative;
2. Where possible, programs will be uniform across the service territories of the Companies, so customers will have equal participation opportunity; and

3. Programs will be multi-year so as to create a sense of funding certainty necessary to effectively implement them in the marketplace.

5.10.2 CEO – Portfolio Overview: Existing and New Programs

Several initiatives undertaken in 2009 launched in Q4 of that year and are continuing into 2010. As many of these initiatives are still very new to the market, they have not had time to achieve momentum. Evaluation of the initiatives will be conducted at completion. For the proposed evaluation budget refer to Section 5.13.3.4 and for a further description of techniques for evaluation for this Program Area, refer to Appendix D.

New initiatives are also being pursued in 2010, some of which include ethnic outreach and employee education. Table 5-21 summarizes the initiatives and proposed expenditures for 2010, which align with the approved funds for the CEO program area for TGI and TGVI.

Table 5-21: 2010 CEO Initiatives and Proposed Expenditures

	Initiatives	Description	Expenditures ($000s)		Total Expenditure ($000s)
			TGI	TGVI	
1	Print and Online Publications	Energy conservation education promoted through bill inserts, newspaper and magazine ads, trade show guides, newsletters, directories, and terasengas.com.	165	33	**198**
2	Ethnic Outreach	Targeted in-language (Punjabi and Mandarin) online & print media, and event attendance, to reach key ethnic markets.	75	15	**90**
3	Trade Shows and Events	Participation in residential home shows and commercial trade shows to reach customers and educate on energy efficiency rebate programs.	245	49	**294**
4	Students and Schools Outreach	Destination Conservation Beyond Recycling BC Green Games School Assembly presentations	400	80	**480**
5	Energy Champion Program	Educate children and youth about energy conservation behaviour changes, using regional sports team events.	446	89	**535**
6	Team Terasen Outreach	Outreach group delivering the DSM message by connecting with customers at community events and festivals.	112	23	**135**
7	Employee Education	Energy conservation education and action program focused on engaging employees in the Company.	36	7	**43**
	Total (Budget)		1479	296	**1775**

CEO initiatives that will be undertaken in 2010 are described in further detail below.

5.10.2.1 Print and Online

As noted in Section 4.7.4, print and online advertising are more cost effective compared to television and mass media approaches, and will be targeted at customers already inclined to home renovations. Consequently in 2010, the Companies will continue to promote energy conservation through a variety of print and online channels.

The goal of print and online information pieces is to keep conservation top of mind through continued and consistent education. These educational pieces have also been vital among our stakeholders, such as contractors and industry associations, for distribution among their customers and members, so this method of communication will continue. Feedback from the March 11, 2010 EEC Stakeholder meeting has indicated that additional education initiatives provided from the Companies would be valuable for stakeholder members and constituents. Please refer to the Stakeholder Priorities in Appendix F.

5.10.2.2 Ethnic Outreach

British Columbia is a culturally diverse province, and a successful EEC portfolio will be aware of the unique needs of ethnic groups. The ethnic marketing and communications outreach campaign beginning in 2010 is to make conservation education accessible to all customers.

New Canadians - primarily coming from China (23%), India, the Philippines and South Korea[17] - are a main source of population growth and housing demand in British Columbia. Within six months of arrival, 17% of new immigrants to British Columbia are homeowners, and after four years more than half are homeowners. Statistics show that 17% of the British Columbia's do not speak English in their homes as a primary language and in over 28% of those homes, English is their second language.[18] Thus, it is important to communicate conservation information that is relevant and easily understood by these ethnic audiences. Refer to Appendix D for proposed initiatives planned for the ethnic audiences.

5.10.2.3 Trade Shows and Events

The Companies will continue to engage with customers at various home and trade shows around the Province to promote energy conservation, and the new EEC programs.

Similar to Section 4.7.5, the goals for the trade show and event activities in 2010 will be to provide face to face interaction with customers to communicate incentive programs, CEO initiatives and engagement programs, and to provide educational materials that can be distributed or displayed at customers' facilities. Refer to Appendix D for a proposed list of trade shows and events.

5.10.2.4 Student and Schools Outreach

As indicated in Section 4.7.6 school programs run over the September to June time period and so many initiatives will continue into the first half of 2010. For the 2010-2011 school year, the Companies will continue to support educational programs that have an energy conservation

[17] According to the Canadian Mortgage and Housing Corporation's 2009 Annual Provincial Outlook on Housing
[18] http://www12.statcan.ca/census-recensement/2006/as-sa/97-555/tables-tableaux-notes-eng.cfm

component, like Destination Conservation, Beyond Recycling, BC Green Games and school assembly presentations. The goal of these programs is to increase the number, awareness and involvement of schools and students around the province. With continued funding support made available to these programs, this allows for improved planning by teachers and school environmental groups to build on existing knowledge and conservation projects. Lastly, new initiatives and increased engagement on energy conservation with post secondary students will also be pursued. This area of activity satisfies clauses 3(c) and 3(d) of the DSM regulation, which requires a utility to have education programs for school-age and post-secondary students in the portfolio plan in order to be considered adequate.

5.10.2.5 Energy Champion Program

As in Section 4.7.6.5, the goal of the Energy Champion program is to educate children and youth on energy conservation. Similar to the school year, program activations with the various sports teams such as Vancouver Giants, BC Lions, and with teams in the BC Hockey League run from September to April/May. As these partnerships began only in Q4 of 2009, they will be continuing into 2010.

The purpose of these partnerships is to enable the Companies to leverage on traditional media channels, such as radio, as well as the sports teams' online and social media channels - channels that are well developed in the market and reach out to a large number of the teams' fans.

In 2010, an exciting new partnership for the Energy Champion Program with the Vancouver Canucks is being launched. The objective of this partnership is to engage the Vancouver Canucks' audience on energy conservation, through a variety of online and in-game activities. Refer to Appendix D for further detail on executing the Energy Champion program.

5.10.2.6 Team Terasen Outreach

The Team Terasen will continue to reach out to the public at local community events in 2010.

As described in Section 4.7.7, as most of the community events are free to the public, this is a cost effective method for the Companies to reach out to a large number of customers. One of the goals for Team Terasen for 2010 is to increase the number of events attended in the service territories of TGI and TGVI, and expand the geographic scope of events attended beyond the Lower Mainland.

Refer to Appendix D for a proposed list of Team Terasen events.

5.10.2.7 Terasen Employee Education

The Companies employ approximately 1,300 individuals, many of whom are themselves customers – and many of whom regularly interact with customers.

The EEC department has traditionally communicated EEC initiatives and incentive programs to employees via the Companies' intranet, newsletters and training specifically for the call centre staff. The goal of the Terasen Employee Education program is to create a large group of "EEC Ambassadors" within the Companies that are able to promote EEC programs and initiatives which they can engage in for their own benefit, as well as communicate EEC programs and initiatives in their dealings with the public, friends and family.

The expansion of EEC initiatives and programs makes it necessary to provide the Companies' employees with continual education on all EEC programs, incentives, CEO activities and initiatives being implemented.

5.10.3 Summary

The objective of CEO initiatives is to keep conservation top of mind with customers, thus supporting the development of a conservation culture within British Columbia.

The 2010 CEO initiatives follow many of the same Program Principles that were put forth in the EEC Application. Universality and accessibility to all customers, uniformity across TGI and TGVI service territories, and the notion that multi-year programs are ideally suited to ensure effective implementation and stability in the marketplace.

The initiatives promote and educate the public on energy conservation behaviours which benefit the community and help embrace change. The CEO activities inform the public about the Companies' conservation initiatives and result in increased participation in EEC incentive programs.

5.11 Interruptible Industrial Sector Programs

As discussed in Section 3.2, TGI sought funding approval for EEC Programs for Interruptible Industrial customers in the 2010-2011 Revenue Requirements Application. As part of the NSA, the parties agreed that EEC funding for Interruptible Industrial programs for 2010 would be $435,000. These programs will focus on mitigating the risks associated with large financial investments in energy efficiency for interruptible industrial customers.

TGI is currently in the process of developing a strategy for EEC for Interruptible Industrial customers; however, the broad areas of activity for this program area for 2010 are not expected to deviate significantly from the information put forward in the 2010-2011 Revenue Requirements Application.

The Industrial Stakeholder group will be re-convened and significant input garnered from this group on program design and implementation. The main area of activity in the Interruptible Industrial Program Area for 2010 will be to undertake the Energy Savings Potential Studies identified in the proceeding.

The Companies believe these investments in this portfolio will better lay the foundation for significant capital investments by large industrial customers and that these investments can produce significant reductions in commercial energy use.

5.12 Innovative Technologies

Innovative Technologies are best described as market ready technologies that have little or no market penetration in the BC energy efficiency landscape. They can be defined as emerging and/or enabling technologies. Some of these technologies include, but are not limited to, solar thermal DHW systems, GSHPs, hydronic systems, sterling engines, micro co-generation, natural gas transportation, and fuel cells. Hydronic systems can be classified as enabling technologies as they have the flexibility and potential to receive future energy from District Energy Systems ("DES"). Innovative Technologies are solutions the Companies can support though programs delivering energy reductions and savings to our customers for now and into the future.

5.12.1 Funding in Place for 2010-2011 Program Development

As discussed in Section 3.2, TGI and TGVI sought funding approval for EEC Programs related to Innovative Technologies in their respective 2010-2011 Revenue Requirements Applications. In November 2009, TGI received approval for Innovative Technologies program budget of $2.334 million in 2010 and $4.669 million for 2011, for a total budget of $7.003 million. TGVI also received approval for Innovative Technologies budget of $478,000 in 2010 and $958,000 for 2011, for a total budget of $1.435 million.

As part of their respective NSAs, the parties agreed that the Innovative Technology Programs will be managed by TGI and TGVI as a separate segment of the overall EEC portfolio.

5.12.2 Late 2009 – Early 2010: Working With Stakeholders

Stakeholder consultation has been a critical component in laying the foundation for future Innovative Technology programs. As discussed in Section 4.9, an EEC Stakeholder Group was formed in December 2009, and had its second meeting on March 11, 2010 (the details of which are provided in Appendix F).

The meeting achieved several important goals; it:

- Provided an opportunity to discuss details of how the weighted average TRC is applied to the Innovative Technologies portfolio. It also allowed the group to discuss proposed Innovative Technologies program portfolio and program costs.
- It introduced the EEC Stakeholder Group to the feedback mechanism that affords them an opportunity to voice any concerns on the Companies' approach to Innovative Technologies, and to provide ongoing dialogue.

Following the meeting, the Companies' Manager of Technical Sales Support sent a request for feedback from the Stakeholder Group. The goal was to ensure any concerns they may have with the practical application of the weighted average TRC or with the portfolio of proposed activity for Innovative Technologies have been brought forward and noted. At the time this report was written, we received feedback from two members of the Stakeholder Group – and since no opposition on the proposed Innovative Technologies portfolio and TRC approach had been voiced, it seems reasonable to conclude the Stakeholder Group is supportive.

5.12.3 Late 2009 – Early 2010: Establishing the Innovative Technologies Framework

At a high level, TGI and TGVI also took important actions to lay the groundwork for the introduction of incentive programs for Innovative Technologies in 2010. Specifically:

- TGI and TGVI restructured the existing portfolio list of Innovative Technologies to include Solar Thermal Hot Water, NGV for Commercial Vehicles, Hydronic and Combination Space Heating Systems, Residential GSHP and Commercial and Industrial GSHP Systems. TGI and TGVI will treat NGV fuel switching from diesel as part of or normal course of EEC activities.

The restructured Innovative Technologies portfolio is described below in Table 5-22 and Table 5-23, along with possible program costs and the relevant TRC weighting of technologies. As program design progress, some technologies may be replaced in the portfolio. However the weighted average of the portfolio will be 1.0 or greater.

Table 5-22: Innovative Technologies Portfolio Program Cost Breakdown TGI

	Incentive Expenditures ($000s)	Non-Incentive Expenditures ($000s)	Total Expenditures ($000s)	TRC
Solar Thermal Hot Water	240	48	$288	0.8
NGV Commercial Vehicles	800	8	$808	1.5
Hydronic and Combination Heating Systems	100	20	$120	0.4
Residential GSHP Systems	100	7	$107	0.2
Commercial/Industrial GSHP Systems	600	5	$605	1.0
Total	**1,840**	**88**	**$1,928**	**1.2**

Table 5-23: Innovative Technologies Portfolio Cost Breakdown TGVI

	Incentive Expenditures ($000s)	Non-Incentive Expenditures ($000s)	Total Expenditures ($000s)	TRC
Solar Thermal Hot Water	$50	$10	$60	0.6
NGV Commercial Vehicles	$166	$2	$168	1.4
Hydronic and Combination Heating Systems	$21	$4	$25	0.4
Residential GSHP Systems	$21	$1	$22	0.2
Commercial/Industrial GSHP Systems	$125	$2	$127	1.1
Total	**$383**	**$19**	**$402**	**1.2**

5.12.4 Striving to Establish Appropriate Incentives

TGI and TGVI recognize how critical it is for the Innovative Technologies portfolio to carefully set and offer incentives.

Further to this, the Companies intend to remove the Partner Incentive Costs currently provided for Solar Thermal from the TRC calculations for the Innovative Technologies portfolio. Utility incentives for Innovative Technologies are designed to promote emerging technologies. As in the case of solar thermal, incentives are provided by the local, provincial and federal governments. These incentives are also intended to encourage the adoption of this technology.

As the California Standard Practice Manual states "… *all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test.* ***Any tax credits are considered a reduction to costs in this test*** (Emphasis Added)". Therefore the Companies believes that Partnership Incentives that come from local, provincial and federal governments may be treated as if they are a tax credits and will be applied to reduce the costs of the technology in the test.

While the Commission and the Companies agree the Innovative Technologies Portfolio will have a weighted average TRC of 1.0 or greater for 2010 and 2011, the Companies may seek the Commission's approval allowing a weighted average TRC of less than 1.0 in future filings. By their nature, Innovative Technologies are new and costs for encouraging adoption may be high, but early experience is necessary to develop knowledge and encourage market uptake.

5.12.5 Summary and Next Steps

Innovative Technologies represent an important component of the Companies' overall commitment to EEC activities. There is appropriate funding in place, and a forum for stakeholder consultation and feedback has been established. Inventive Technologies are solutions the Companies can support though programs delivering energy reductions and savings to our customers for now and into the future.

The next step: TGI and TGVI will begin program design in Q2 2010 for Innovative Technologies.

5.13 Enabling Activities

As discussed in Section 4.8, in 2009 the Companies pursued Enabling Activities in support of broader EEC activities and programs. They fall into four major categories: Research and Evaluation, Efficiency Partners Program, Codes and Standards and Pilot Programs. In 2010 these four areas of focus will remain the same and the Companies will increase and broaden their planned activities in each.

5.13.1 Broader Commitment In Four Continued Areas of Focus

Research and Evaluation:

The highlights of the 2010 Research and Evaluation activities are as follows:

- TGI and TGVI plan to undertake a thorough investigation of the gas savings associated with the Efficient Boiler Program. The results of this investigation will serve to confirm or modify the underlying assumptions currently used to evaluate this program and to establish incentive levels.
- TGI will empirically evaluate the results of the Okanagan Spray N' Save program that took place in 2009. The results will be used to establish a reasonable and prudent

estimate of the gas savings attributable to low flow spray valves, and the program more generally.

- TGI and TGVI are engaged in an evaluation of the Energy Assessment Program This exercise will evaluate program effectiveness, verify energy savings, and identify areas of improvement via billing analysis and phone based interviews.
- CEO activities to be evaluated for effectiveness through methods such as: advertising tracking, process evaluations, and web analytics.

Efficiency Partners Program:

As described in Section 4.8.3, 2009 provided a good starting point to develop the Efficiency Partners Program. The highlights of the 2010 Efficiency Partners program activities are as follows:

- Contractor program focus group meetings will be held in the Lower Mainland and Interior to gather input from contractors on what elements of a contractor program they would find to be of most interest, and most beneficial to them and our mutual customers.
- Develop and roll-out the new Contractors program.
- Develop and start quarterly Efficiency Partners newsletters.
- The Co-op Advertising program will still be available for those that are registered with the Company's contractor program and a review of the value of this element will be conducted.

Codes and Standards:

A full listing of all monitored areas of regulation can be found in Section 4.8.4. EEC will remain active with developments on Code and Standards committees as they pertain to EEC program and market development, and this will continue to be an important activity area. The activity highlights for the Codes and Standards for 2009 are as follows:

- In 2010, monitoring and participation in developing codes and standards that have relevance to EEC program areas will enable the EEC team to anticipate, develop and implement effective programs.
- Of particular interest in 2010 will be the development of the BC Building Code for new home construction with EnerGuide 80 efficiency targets.
- Residential Hot Water heater regulations will continue to require a partnership with government and manufacturers to achieve a market transformation plan.

Pilot Programs:

In 2010, EEC plans to expand this area by including six new pilot programs. The highlights for the 2010 Pilot Programs are as follows:

- Behaviour Change Pilot Programs are currently in development to influence commercial and municipal customers' behaviour and if successful, the program design will expand to other large commercial, institutional, and municipal customers.
- The Custom Design Pilot Program is slated to be offered to commercial programs in 2010. The program seeks to capture energy savings associated with measures and systems (technologies or operational strategies), which are otherwise difficult to incent as part of a prescriptive program. It will apply to measures which reduce gas consumption of space and / or domestic hot water heating, for both new construction as well as retrofits.
- Fireplace Timers Pilot Program is in currently in market, and aims to study the effect that installing electronic timers on 'decorative' natural gas fireplaces in multi-family residential strata and apartment buildings has on natural gas consumption.
- A Tier 3 Domestic Hot Water Heater Pilot Program to confirm energy savings and build a knowledge base as we approach 0.80 EF regulations in 2013. All viable technologies will be identified and tested including condensing tankless and condensing storage tank systems. This pilot will include technical issues, installation difficulties and establish methods for overcoming marketing barriers.
- Drain Water Heat Recovery Pilot Program will be conducted to validate manufacturers' claims about energy efficiency on the technology.
- The EnerGuide 80 Pilot Program for new homes and retrofits to determine the best way to incent customers and builders to adopt more energy efficient building practices.

5.13.2 Enabling Activities Budget

The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the overall portfolio level expenditures.

The Commission did not approve the EEC discrete Trade Relations budget area put forward for these supporting activities as it was identified as a duplication of commercial and residential program delivery expenditure.

As the Companies' EEC initiative continues to expand through 2010 and beyond, the Efficiency Partner and Codes and Standards areas have the potential to consume significant resources. As the Efficiency Partner and Codes and Standards areas develop, it may be necessary to reassess the need to establish a separate Program Area for these activities in the future, with its own budget.

Table 5-24 below shows the budgeted amount for Enabling Activities for 2010.

Table 5-24: 2010 Expanded Enabling Activities Budget

Program		Description	Expenditure ($000s)	
			TGI	TGVI
1	Research and Evaluation	Market research used for planning & implementing programs and measure program/activity effectiveness	452	113
2	Efficiency Partners Program	Delivering EEC programs through B-Ticket Contract Companies	311	78
3	Codes and Standards	Codes and Standards related to EEC Program areas	40	10
4	Pilot Programs	Test the effectiveness of measure/activity in the market	1,146	287

Further information on each of the four areas of the 2010 Enabling Activities is listed below.

5.13.3 Research and Evaluation

In addition to the Conservation Potential Review Study, discussed in detail in Section 6, the Companies' EEC group has a number of other research and evaluation projects planned for 2010 outlined below.

Note that this is not an exhaustive list and may change as the year progresses, based on business priorities. Those initiatives currently planned are discussed below.

The estimated costs associated with these activities are also shown in Table 5-25. The first line item in the Table is a contingency amount of $100,000 for potential studies that the EEC team might undertake in 2010 the subjects of which have not yet been identified. The second line item in the table of $33,000 includes two studies carried out in 2009 as shown in Table 4-18 : $15,000 for the second milestone of the Sustainability & Social Responsibility Attitudes Study Report ("SHIFT Report") and $17,800 for Residential Retrofit Market Evaluation for Terasen Gas. Due to the timing of these two studies, these payments were made in January 2010. Further details for these studies are provided in Appendix D.

Table 5-25: Research and Evaluation Activities 2010 Budget

	Study	Description	Expenditure ($000s)
1	Contingency/Additional Studies	Budget for additional studies & contingency amount	100
2	Variance between 2009 & 2010	Studies conducted in 2009 but paid in 2010	33
3	Efficient Boiler Program Evaluation	Gas savings associated with the Efficient Boiler Program	35
4	Okanagan Spray N' Save Pilot Program Evaluation	Determine average gas savings per spray valve	40
5	Energy Assessment Program Evaluation	Verify energy savings and identify areas of improvement.	18
6	Conservation, Education and Outreach Evaluation (Multiple Programs)	Cost effectiveness of CEO initiatives	340
	Total Estimate Amount		**566**

5.13.3.1 Efficient Boiler Program Evaluation

In 2010, TGI and TGVI plan to undertake a thorough investigation of the gas savings associated with the Efficient Boiler Program. The study will assess the actual savings per boiler installation as well the rate of successful boiler installation. The results of this investigation will serve to confirm or modify the underlying assumptions currently used to analyze the program. The costs of the study are estimated at $35,000. Furthermore, if the proposed methodology does not impose significant administrative costs on the program, it may subsequently be used to track gas savings on an on-going basis. For further details refer to Appendix D.

5.13.3.2 Okanagan Spray N' Save Pilot Evaluation

In the first half of 2010, TGI will evaluate the results of the Okanagan Spray N' Save program that took place in 2009. The cost of the study is estimated to be $40,000. Results will be compared and used to establish a reasonable and prudent estimate of the gas savings attributable to this technology program.

The initial phase of the evaluation has been completed. It consisted of an arithmetic analysis of participant specific survey information collected by the program operator at the time of low flow spray valve installation. The analysis made use of the recorded water flow reduction volumes and output water temperatures as well as the average ground water temperature in the Okanagan region and the estimated spray valve operating hours to determine the average gas savings per spray valve. Preliminary analysis suggests savings of approximately 8.71 GJ/yr.

In the second phase of the evaluation, approximately 30 participants will be selected for metering of their actual hot water consumption in order to empirically confirm the gas savings associated with the spray valves. For further details on this subsequent phase of the evaluation study refer to Appendix D.

5.13.3.3 Energy Assessment Program Evaluation

TGI and TGVI are currently in the process of evaluating the performance of the Energy Assessment Program. The goal of this evaluation study is to evaluate program effectiveness, verify energy savings and identify areas of improvement.

In 2008, the Companies retained a consultant to perform an evaluation study of the Commercial Energy Assessment Program for the period of mid – 2005 through June 2007. The study determined that approximately 35% of customers who received Terasen Gas energy assessments implemented some or all of the recommended measures and that the total amount of energy savings resulting from audits conducted during the 2005 -2007 audit period was 129,000 GJs.

In January 2010, the same consultant was retained to conduct the second wave of the study. The company was awarded the contract to maintain the continuity of the project and to manage costs; the cost of the second wave was $17,800. Starting in January 2010, the consultant interviewed 53 participants out of the 158 customers who participated in the Commercial Energy Assessment program between July 2007, and July 2009. These customers included the following groups: care homes; manufacturing companies; apartments and stratas; hotels and restaurants; as well as large public facilities and offices.

It is anticipated that the complete finalized report will be available by the end of April, 2010.

5.13.3.4 Conservation Education and Outreach Evaluation

As several new CEO initiatives have been introduced into the portfolio, it has become increasingly important to evaluate the cost effectiveness of CEO initiatives in order to justify the expenditures associated with these activities. The estimated budget for evaluation of the CEO activities is set at $340,000 (which is based 15% of the overall CEO budget for 2010). The Companies intend to use these funds to evaluate CEO programs in 2010.

CEO initiatives are diverse and can vary in nature. Their effectiveness can be measured through methods such as: advertising tracking, process evaluations, and web analytics. These evaluation methods will be used to evaluate the CEO initiatives described in Section 5.10.

Advertising tracking can investigate the effectiveness of specific commercials or campaigns in terms of the recall of specific messages, changes in people's perceptions, and behavioural changes in the target audience. Process evaluations measure the effectiveness of the program by assessing how well the program met a set of goals or metrics defined by the program administrators. Web analytics is the process of understanding the Companies' online presence so that it can be optimized. Modifications to improve the initiatives can take place once one or more of these forms of evaluation takes place. For a further description of the evaluation techniques for CEO initiatives, please refer to Appendix D.

The specific methods to evaluate each CEO initiative will be selected later in the year and depending on the scope of the evaluation, may be assessed internally or evaluated by an independent research firm.

5.13.4 EEC Efficiency Partners Program

Strong uptake of EEC programs through the course of 2010 will require strong Efficiency Partner group support. It is important for industry stakeholders with end-use customer influence to be aligned with the Companies' stance of promoting high efficiency appliances, due to their direct customer contact. To promote this support the Companies will broaden their Partners Program in 2010.

Focus groups will be held in the Lower Mainland and Interior; the focus will be the development of the new Contractor program. These focus groups will differ from those held on Vancouver Island in 2009, as there is no established Qualified Dealer Program in the Lower Mainland and Interior. The purpose of these meetings is to gather input from contractors on what elements of a contractor program they would find to be of most interest, and most beneficial to them and the Companies' mutual customers. Program framework and procedures will be developed based on information gathered and the new program will be rolled out in conjunction with a new name and logo in the second and third quarter of 2010.

The focus of the second and third quarter of 2010 will be on promoting the program to contractors. From second quarter to year end, the focus will be on registering contractors in the program. Energy efficiency workshops will be offered in the last quarter of 2010 with the support of equipment suppliers.

Direct contact with gas contracting companies, manufacturers, suppliers, and other service groups connected to the gas industry (e.g. home auditors and inspectors) is essential; these groups must be educated as to the benefits of high efficiency equipment and their concerns of availability and complexity assuaged.

Table 5-26 is an estimate of the expenditures required to develop and maintain the 2010 contractor program.

Table 5-26: Expanded 2010 Contractor Program Budget

Contractor Program	Expenditure ($000s)	
	TGI	TGVI
Promotion, Brochures and Trade Magazine adds	8	2
Conference and Trade Shows	40	10
Application Admin $5.00 per	4	1
Quarterly Contractor Newsletter	19	5
Program Development Labour	72	18
Program Development Expenses	40	10
Efficiency Work Shops	72	18
Website portion development with user tools	16	4
Co-op Advertising	20	5
Total	**291**	**73**

To help promote energy efficient natural gas products and services, a Co-op Advertising program will still be available for those that are currently registered with the Company's contractor program. In the future, Co-op Advertising will be included as part of the program package for the new Contractors' Program.

The 2009 guidelines (as discussed in Section 4.8.3) will remain in effect with the addition of an energy efficiency component or promotion of an EEC Program. Table 5-27 identifies estimates of the Co-op advertising reimbursement activity projected for 2010 by quarter.

Table 5-27: Co-op Advertising Reimbursement Estimate

Contractor Co-op Advertising	Expenditure ($000s)				
	Q1	Q2	Q3	Q4	**Total**
TGI	2	3	7	7	**20**
TGVI	1	1	2	2	**5**

Increased levels of participation in the Co-op advertising program are expected as the numbers of participants increase in the new Contractor program. A review of the current structure and effectiveness of the Co-op Advertising program is underway and adjustments will be made as the year progresses.

The Efficiency Partners New Contractor program is further discussed in greater detail in Appendix D of this Report.

5.13.5 Codes and Standards

In 2009, current codes and standards that have relevance to EEC program development and implementation were benchmarked for monitoring. See Section 4.8.4for details of Codes and Standards as they pertain to EEC program areas. The regulatory focus for 2010 will be on the new construction building code to EnerGuide 80 development, and the Residential Hot water storage tank Tier Three regulations starting at 0.61 EF and ending at 0.80 EF.

As mentioned before in Section 4.8.4.3, the Provincial Government has announced that they are working toward the implementation of EnerGuide 80 ratings for the BC Building Code to take effect in late 2010. The current rating of EnerGuide 77 and the new EnerGuide 80 rating are stepping stones toward a Net zero level set for 2020. The Province of British Columbia is updating the energy efficiency requirements for residential buildings in Part 10 of the BC Building Code. Along with Industry stakeholders, a study was started in 2009 to determine potential combinations of overall building envelope thermal requirements, air tightness, and equipment efficiency which will meet EnerGuide 80.

A modelling study is complete and a stakeholder committee has been struck to develop the guidelines for changes to the BC building code based on the results of the modelling study and input from the representing groups. Actual implementation of the code changes are targeted for September of 2011. As a partner in this code development, it is important to ensure the code does not dictate energy type. New homes may require different construction processes for different fuels at this efficiency rating.

As mentioned previously, actual measurement of the EnerGuide ratings may be compulsory in the new code. A review of the existing D audit process, including the fuel use inconsistencies of the *HOT2000* software that is currently in use, will be required. With whole home labelling and industry moving toward performance measurement, more weight will be placed on the resulting EnerGuide rating of the home. Utility representation is vital as decisions related to the BC Building Code will affect Companies' EEC programs. This EcoEnergy audit review will be conducted under the Joint Initiatives program area, see Section 5.9.1.2.

As industry moves toward a net zero energy or net zero energy capable construction code (also known as the Passive House) by 2020, each tier of code development demands lower energy utilisation, increasing the cost of building design, construction techniques, and insulating materials that make up the building shell. At the EnerGuide 85 efficiency level, energy generation devices must be utilized for any further efficiency gains. These differences are also affected by the type of energy utilised to heat the home. Terasen Gas participates in both the EnerGuide 80 and Net Zero committees as the first leads to the second as an end goal. Below is the definition of a Net Zero home:

- A net zero home, at a minimum, supplies to the power grid, an amount equal to the total amount of energy consumed. Combining the amount of energy (electricity and if applicable natural gas) utilised to operate a home and provide an equal amount of solar generated energy back to the grid when possible. A Passive house generates and stores all it requires without connection to any utility supply.

In the area of domestic hot water, government has announced plans to introduce three-tier efficiency regulations in 2010 leading to a regulation requiring a minimum EF of 0.80 in 2013. The Companies' approach to water heater market transformation is discussed in greater detail in Section 8. 2010 will see a continuation of the Companies' work on Residential Domestic Hot Water Regulations discussed in Section 4.8.4.5.

In 2010, monitoring and participation in developing codes and standards that have relevance to EEC program areas will enable the EEC team to anticipate, develop and implement effective programs. The planned budget for this area of activity for 2010 is estimated at $50,000; this is based on a time commitment equivalent to ½ full-time position.

5.13.6 Pilot Programs

In 2009, two Pilot Programs were conducted and with the growth of all Program Areas, Pilot Programs will become the second step after research in developing effective new EEC programs. To date, there are six Pilot Programs underway or planned to start in 2010.

Table 5-28 identifies estimates of the Pilot Programs activity projected for 2010.

Table 5-28: 2010 Estimated Pilot Programs Activities - Budget

	Pilot Program	Description	Expenditure ($000s)
1	Behaviour Change Pilot Programs (Commercial & Institutional Pilot)	Commercial & Institutional Pilot: Online tool where users learn about energy conservation, and make social commitments towards behavioural changes and GHG reducing actions.	485
2	Behaviour Change Pilot Programs (Municipalities)	Municipalities Pilot: staff engagement plan for 5 municipal customers	25
3	Custom Design Pilot	Incentive program to encourage energy savings via otherwise difficult to incent measures	457
4	Fireplace Timers Pilot	Pilot program to evaluate the effectiveness of time of operation control devices on decorative fireplaces	75
5	Domestic Hot Water Tier Three Technologies Pilot	Initial studies to develop market transformation for Tier Three Water Heater Systems	250
6	Drain Water Heat Recovery Pilot	To validate manufacturers' claims regarding energy efficiency	25
7	Home Labelling Pilot in Price George	To raise awareness of the value of purchasing an energy efficient home	10
8	EnerGuide 80 Pilot Program	To develop new building code standard for EnerGuide 80 (New Construction & Retrofit)	80
9	TGVI Servicing Pilot Program	To promote the benefits of annual furnace servicing (carry over from 2009)	26
	Total		**1,433**

5.13.6.1 Behavior Change Pilot Programs

The Companies are currently exploring programs that can influence commercial, institutional and municipal customer behaviour. The goal of the behaviour change pilot programs is to develop a successful program design and then expand to other (large) commercial, institutional and municipal customers.

Behaviour change, or community based social marketing, looks to identify the barriers to behaviour change, design a strategy utilizing behaviour change tools, and then implement that strategy.

The benefits of implementing a behaviour change program include understanding the psychological and motivational aspects of human behaviour in decision-making and the power of community and peer influence to develop an engagement strategy that may have a longer-lasting impact than traditional mass media campaigns.

In dealing with some commercial, institutional and municipal customers, they have anecdotally indicated that as they are strapped for financial resources, they have to focus their efforts in low cost, or no cost, behaviours in an effort to reduce energy costs. Refer to Section Appendix D for detailed examples of behaviour change pilot programs the Companies are pursuing as a result of customer demand.

5.13.6.2 Custom Design Pilot

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI and TGVI: May 2010 – December 31, 2011

The Custom Design Pilot is currently in development. It is slated to be the next major Commercial Energy Efficiency Program Area offering of 2010 after the Efficient Water Heater Program. The program seeks to capture energy savings associated with measures and systems (technologies or operational strategies), which are otherwise difficult to incent as part of a prescriptive program. Running the Custom Design Pilot in 2010 will allow the company to develop experience with a large scale, non-prescriptive program, while evaluating the assumption underlying the proposed incentives for appropriateness. Learning from 2010 can then be incorporated into a full-blown Custom Design program for 2011.

This pilot will apply to measures which reduce gas consumption of space and / or domestic hot water heating, for both new construction as well as retrofits. Process loads and fuel switching measures other than to renewable energy sources will not generally be eligible for participation in the program. However, measures which recuperate waste heat from manufacturing process for use in reducing space or hot water heating requirements may be eligible.

The Custom Design Pilot will capitalize upon the creative potential of the marketplace, and help foster expertise in advanced energy efficiency design in the province of BC. The program will build additional insight into energy efficiency within Terasen Gas.

The proposed Custom Design Pilot consists of two components:

a) A fully funded energy study (up to $50,000) to estimate the potential energy savings from client proposed measures
b) A capital cost incentive (initial estimate of approximately $3/GJ saved) based upon the estimated energy savings and expected persistency of the measures implemented by the client

The Companies are working with BC Hydro in view of harmonizing the energy study requirements of the proposed Custom Design pilot with those of BC Hydro's Power Smart Partners and Commercial New Construction programs. The utilities aim to allow participants in either BC Hydro's programs or the Companies' programs to have a single energy study performed, which could be submitted for incentive funding at both the gas and electricity utilities. The budget for 2010 for this complex Pilot is $457,000; the high costs are associated with the engineering studies required for this pilot.

5.13.6.3 Fireplace Timers Pilot

Program Area: Commercial Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI and TGVI: Present – March 31, 2011

The purpose of the Fireplace Timers Pilot is to study the effect that installing electronic timers on 'decorative' natural gas fireplaces in multi-family residential strata and apartment buildings has on natural gas consumption. Should the gas savings potential prove significant enough, the pilot can be rolled out as a full scale program.

Decorative gas fireplaces are those which are installed to provide ambiance as opposed to space heat. It is believed that these fireplaces tend to be used excessively when they are present in apartment buildings or stratas in the absence of a user-pay scenario (i.e. the occupant who consumes the gas via the fireplace does not pay a bill associated with its operation). Selected participants who comply with all of the program requirements will be eligible to receive free timers and an incentive of $30 per timer installation.

Preliminary studies have suggested that the gas saving potential of these timers could be as high as 6 GJ/yr per fireplace, while market research indicates there are approximately 17,000 decorative gas fireplaces in multi residential buildings in the Vancouver area alone. The evaluation of the results, slated for spring of 2011 (after the timers have been in operation for 1 full heating season) will confirm the savings obtained per timer. The budget for this pilot program is set at $75,000.

5.13.6.4 Domestic Hot Water Tier Three Technologies Pilot

Program Area: Residential Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI and TGVI: Present – March 31, 2011

Provincial regulations may require that all hot water tanks manufactured be Tier Three (EF 0.80 or greater) as early as 2013. Given that Tier Three technologies are fairly new to residential applications, the Companies will develop a pilot to confirm energy savings and build a knowledge base about Tier Three technologies, including technical issues or difficulties in installation and end-use.

Water heating accounts for approximately 20% of energy use in an average residential home, so increasing the efficiency factor of water heating appliances can have a significant impact on total energy use. Habart developed an implementation plan for market transformation in the condensing water tank market, in a recent report commissioned by the Companies and attached in Appendix I. The report outlines the importance of conducting a pilot for condensing water tank technology, due to the newness of the product, and further identifies pilots as an opportunity to provide training to the contracting community as well as to develop relationships with manufacturers and distributors, ensuring that the product can reach the shelves for consumers.

Tier Three technologies are varied, but two important methods for achieving Tier Three efficiency levels (EF 0.80 or greater) are condensing hot water tanks and tankless water heaters.

- A condensing water heater is similar to a standard efficiency gas storage water heater but has an improved heat exchanger that allows thermal efficiency ratings as high as 96% and recovery rates as much as four gallons per minute.

- On-demand or "tankless" water heaters heat water only as it is needed and used. This equipment may incorporate condensing technology with resulting efficiencies higher than 90%.

Working with a variety of manufacturers, the Companies will measure the gas and water consumption in approximately 20 homes for 6 months, installing the Tier Three technologies after three months, and measuring the difference in energy consumption between the three months prior to installation and the three months following the installation of the Tier Three tanks. The Tier Three Technologies pilot is in the early design stages and the structure of the pilot is subject to change, based on feedback from industry, manufacturers, and contractors.

The pilot will also give the Companies the opportunity to work with manufacturers and contractors to provide training on Tier Three Technology installation procedures. They will also have the opportunity to help develop solutions, in advance of regulations, to technical and marketing issues.

The budget for the Tier Three technologies pilot is expected to be $250,000 to cover the purchase and installation of 20 Tier Three tanks, the purchase and installation of sub-metering devices for gas and water flow, and pilot evaluation. This pilot is the foundation for all future programs with the primary objective of water heater transformation that will result in significant energy savings across the residential sector.

For further details refer to Appendix D.

5.13.6.5 Drain Water Heat Recovery Pilot program

Program Area: Residential Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI and TGVI: Present – March 31, 2011

The Companies will conduct a pilot program to identify opportunities to save energy through Drain Water Heat Recovery technology.

At first glance there seems to be a significant opportunity for savings. Conventionally, most of the heat from domestic hot water is washed down the drain. Drain Water Heat Recovery technology can capture large amounts of wasted heat energy by using it to preheat the incoming cold water thereby substantially lowering water heating costs. Consisting of a copper potable water tube wound and moulded around a central copper drain tube, heat is transferred from the waste water flowing down the drain tube to the cold water simultaneously moving upward through the wound coil. The water can be increased by as much as 15°C by the Drain Water Heat Recovery unit.

Since this is new technology, pilot tests will be conducted to confirm energy savings, develop the cost benefit analysis, and develop a drain water heat recovery program for new construction. The estimated costs to run this pilot in 2010 are $25,000.

Given that this pilot is in the very early stages of development, it requires discussions with a large number of stakeholders. The Companies are evaluating available market and technical data to establish a sound business case and cost benefit analysis.

5.13.6.6 Home Labeling Pilot in Prince George

Program Area: Residential Energy Efficiency Programs

Target Market: Retrofit

Duration: Prince George: Present – March 31, 2011

The Companies have agreed to partner with the City of Prince George and MEMPR to provide $10,000 each in marketing support to this initiative. The City of Prince George will encourage home sellers/buyers to conduct an energy audit for houses before they are listed for sale.

The program provides a $75.00 rebate to home sellers for participating in a home energy audit. In addition to the home energy audit, home sellers are required to work with their local Real Estate agent to post the audit outcomes on Multiple-Listing Service MLS®. Posting the EnerGuide Rating on MLS® provides information to the new home owner on the energy efficiency of the home, therefore increasing home marketability.

Before a province wide program can be considered this pilot will help identify:

- potential changes required to the home auditing process to insure consistency
- potential label format and mounting location
- marketing strategies to gain acceptance

One of the major objectives of the Industry and Government is to establish Whole Home Efficiency Labelling, which would provide a label to be mounted on a home, posting an EnerGuide performance rating. The posted efficiency rating will be a valuable tool for home buyers, raising awareness of the value in purchasing an energy efficient home. This pilot will provide a good first step toward a potential Province wide program.

5.13.6.7 EnerGuide 80 Pilot

Program Area: Residential Energy Efficiency Programs

Target Market: New Construction / Retrofit

Duration: TGI and TGVI: Present – March 31, 2011

At present, the Province of British Columbia is in the process of evaluating and developing new building code standards which would move the current EnerGuide 77 efficiency rating to a new target of EnerGuide 80 for new home construction. There is potential for the Companies to provide incentives to encourage the early adoption of EnerGuide 80 ratings for new home construction, and to provide existing gas heated homeowners with incentives to perform efficiency upgrades that result in EnerGuide rating improvements.

EnerGuide home efficiency performance levels are determined by performing Home Energy Assessments. Older homes need periodic renewal of major energy efficiency components including windows, furnace, and fresh air ventilation systems, so the actual score of a 20 year old home will depend in large part on whether these systems have been updated or are original. The EnerGuide 80 retrofit program would help customers increase the EnerGuide rating of their home, and aid in preparing the market for a home labelling requirement before mandatory requirements are established.

Currently, there are two compliance paths that builders and developers can follow to meet the building code EnerGuide 77 standard: Prescriptive and Measurement. The Prescriptive path exists in the code as a guideline or recipe to build a home that potentially meets the EnerGuide 77 level. A Measurement path requires the measurement and verification of the actual performance level of the home through New Home Energy Assessments, performed by a contractor working in concert with the builder. If the update to the BC Building Code in late 2010 recommends eliminating or discouraging the prescriptive path, all new home constructions will require a New Home Energy Assessment.

Retrofits

Incentives for retrofits in the EnerGuide 80 program will focus on moving older houses up the EnerGuide scale. The EnerGuide 80 program would potentially assign incentives based on the number of points a house moves up the EnerGuide scale

New Construction

As new building codes will not take effect until mid-2011, now is the time to encourage builders and developers, through incentives, to begin building homes to the EnerGuide 80 standards. Ideally, incentives will help builders and developers define the prescriptive measures that will achieve EnerGuide 80 standards, and prepare the market for the new building code changes.

The estimated budget for this pilot program is $80,000. For further details refer to Appendix D.

5.13.7 Summary

Enabling Activities are important initiatives that support broader EEC activities and programs. The Companies initiated these activities in 2009 in four categories, and as outlined above, the amount of activity for all four areas will increase dramatically in 2010. This increase is designed to further create supportive conditions for a successful 2010 EEC portfolio.

Research and Evaluation activities have a number of studies planned and the list of Pilot Programs will expand as well. The Efficiency Partners Program will grow to include the TGI service area represented by potentially adding another 1000 contractors delivering EEC programs. Given the aggressive BC government provincial emission targets, participation in the development of the new construction building code will strengthen our communication with the building industry. Hot water tank regulations and tier three pilots will be necessary for the development of an effective market transformation plan to help protect the end use customer.

Many of these enabling activities are supportive of the province's Energy Plan. The degree of the Companies' work in Enabling Activities will be evaluated over the course of the year to determine whether the Efficiency Partners program and the Codes and Standards work require the establishment of a discrete budget for this work.

5.14 EEC Stakeholder Group Activities

The EEC Stakeholder Group serves an important function; it provides the Companies with guidance and input on its EEC activities. The Group first met in late 2009, and has since indicated it is supportive of planned activities. In 2010 the Companies intend to continue working closely with the Stakeholder Group to gain their insight and perspective as the broader EEC Portfolio is rolled out.

5.14.1 Planned Activities

Two meetings are planned for 2010 with the EEC Stakeholder Group with the first meeting having already taken place on March 11.

The March 11 meeting afforded each group the opportunity to understand each other's respective organizations. The EEC department asked the stakeholders to present their organization's priorities and described how the Companies can help each of their organization. The Companies provided this information, and also presented on an overview of alternative energy solutions and innovative technologies program area. Finally they reviewed with the group at a high level the contents of this EEC Annual Report.

The agenda, meeting minutes, and list of stakeholder priorities from the March 2010 EEC Stakeholder Group meeting can be found in Appendix F.

The Companies intend to hold an additional EEC Stakeholder Group meeting in Q4 2010 to gather feedback about improvements to existing programs, and potential new programs.

5.14.2 Proposed Budget

Table 5-29 summarizes a proposed budget for the stakeholder sessions.

Table 5-29: Proposed Budget for EEC Stakeholder Group Meetings for 2010

	Expenditure ($)
Venues and Equipment Rental	1,500
Meals	5600
Stakeholder travel and administration	7,500
Total Budgeted Expenditure	**14,600**

5.15 2010 EEC Portfolio: Summary

The Companies' commitment to develop and roll out a comprehensive EEC Portfolio was demonstrated in 2009 and early 2010.

Those programs which were very successful in this early “transition” period will form the foundation of the Companies’ 2010 Portfolio. For example, the Efficient Boiler Program (generating gas savings for commercial customers) will be continued and improved in 2010. The Companies will continue to forge partnerships through Joint Initiatives to draw on the knowledge and expertise of LiveSmart BC, BC Hydro and FortisBC, among others.

The 2010 Portfolio will introduce initiatives and programs that seek to reach more than traditional residential and commercial customers. The Companies will continue their efforts to develop a better understanding of the needs of low-income home-owners and renters so they can assist them in making smart energy choices; the Companies will also work to promote conservation with new immigrants; they will reach out to children and schools; and they will work to create conservation champions from within TGI and TGVI’s employees.

New Program Areas will also be introduced in 2010. The High-Carbon Fuel Switching Program Area lowers GHGs by using natural gas in place of higher carbon fuels. The Interruptible Industrial Program will help large customers become more efficient while also reducing the risk to the Companies and ratepayers associated with large financial investments in energy efficiency. And the Innovative Technology Programs will promote and pilot emerging commercially available technologies.

Through this broader Portfolio in 2010 the Companies are confident they will increase their efforts to promote conservation in all customer classes.

6. CONSERVATION POTENTIAL REVIEW ("CPR")

Results of a CPR form the basis for future program development within a comprehensive EEC portfolio. The Companies drew heavily on the 2006 CPR as they moved from the small set of DSM activities to the broader Portfolio of EEC initiatives. Now the Commission has approved the request for $500,000 to fund a new CPR, and the Companies intend to undertake one and so establish the basis for a request for funding in 2011 and beyond.

6.1 Purpose of CPR

A CPR study examines available technologies and determines their "conservation potential", which includes the amount of energy savings that can be achieved through energy efficiency and conservation programs over the study period, through economic screening. The CPR compares the economic and achievable potential of viable measures to a base case scenario[19]. In general, the CPR has three key objectives:

- Characterization of available natural gas technologies inclusive of energy efficiency and fuel substitution;
- Identification of the size of the potential opportunities over a set study period; and
- Economic modeling of EEC measures, fuel substitution and energy efficiency measures.

6.2 New CPR In 2010 Will Create Important Planning Document

The EEC Decision approved the request for $500,000 for an updated CPR, specifically: "The Commission considered the CPR to be an important tool for use in developing, supporting and assessing this and future EEC/DSM expenditure Applications. The Commission accepted the EEC Application's CPR update expenditure proposal."

In 2010, the Companies intend to develop the requirements for the updated CPR, which would form the basis for an application to the Commission for approval for EEC funding beyond 2011. It is anticipated that the preparation phase will commence during Q2, 2010. The Companies plan to outsource the research, development and delivery of CPR and will release a Request For Proposals for the project with the intent to find the best consultant organization to perform the work. It is estimated that the study will be completed by Q4, 2010.

Similar to the goals of 2006 CPR, the goals of the 2010 CPR are to provide a comprehensive planning document that the Companies can use on an ongoing basis to:

- Develop a long range energy efficiency and fuel choice strategy, including an analysis of the savings opportunities available from the implementation of large-scale Alternative Energy Systems;

[19] Economic Potential is the proportion of energy savings that could be achieved if all measures identified in the CPR were implemented. Achievable Potential is the proportion of energy savings identified in the Economic Potential that could be realistically achieved within the study period. Achievable Potential recognized that it is practically difficult to induce customers to purchase and install all the energy efficiency or fuel choice option that meet the criteria identified in the study.

- Design and implement energy efficiency and fuel choice programs and initiatives;
- Assess the impact of energy efficiency and fuel choice program on both peak and annual loads;
- Identify equipment and technologies that could be used for energy efficiency and fuel choice programs; and
- Set annual energy efficiency and fuel choice targets and budgets.

Assuming the study is launched in April, Figure 6-1 provides a timeline for the rollout of the deliverables for the CPR study.

Figure 6-1: Timeline for CPR study

Task Description	April	May	June	July	August	September	October	November	December
Develop Project Scope									
Issue RFP									
Select Vendor									
Project Start									
Field Research									
Analysis									
Report Writing									
Report Reviewing/Feedback									
Report Presenation									
Final Feedback/Wrap up									

6.3 Summary

The 2006 CPR was an important foundational document for the Companies EEC Application. Now, with the Commission's approval of $500,000 for an updated CPR, the Companies intend to create this revised document that will identify the most compelling EEC opportunities.

When it is completed, the updated 2010 CPR will form the primary basis of the Companies' EEC funding requests for 2012 and beyond, which the Companies anticipate they will submit in 2011. It is the Companies' belief that sustained and stable funding for utility EEC efforts is necessary in order to create market momentum and to support the transformation of the energy market with ever-increasing efficiency levels.

7. DATA GATHERING, REPORTING AND INTERNAL CONTROL PROCESSES

In its EEC Decision, the Commission directed the Companies to include a discussion in the Annual Report of the Companies internal data gathering, monitoring and reporting control practices. This section addresses that direction. As this section demonstrates, the Companies have business practices in place for EEC activities to ensure that these activities are in compliance with the general controls of the Company.

This section provides high level information on data gathering, and on the Companies' business practices related to program development and application processing. It also includes comments from the Companies' Internal Audit group on EEC initiative controls.

7.1 DSM System Project: Meeting the Growing Need for New Tracking and Reporting

The expansion of EEC programs resulting from the EEC Decision has created a need to develop a robust data capture and reporting system. With the anticipated increase in the number of programs and participants, the existing Excel-based DSM tracking and reporting methods would not be capable of handling the future business needs and requirements of the EEC Activities. The Companies determined that a new tracking system was needed to enable it to:

- Track EEC program participation, costs and energy savings for incentive-based programs;
- Track information about non-incentive programs and activities;
- Track actual and forecasts vs. budgets;
- Provide reports for internal and external stakeholders including program partners and the Commission;
- Allow for scenario modelling for program planning and design; and
- Support DSM benefit-cost analysis on a program by program basis as well as at the portfolio level (or EEC plan level).

To address the requirement for more robust program data gathering, tracking and reporting, the DSM System ("DSMS") project was launched in the fall of 2008. The Companies conducted research on the potential solutions available in the marketplace, as well as investigated having a system custom-built.

The Companies eventually selected a web-based program tracking and reporting system called TrakSmart, and entered into an Agreement with TrakSmart's provider Nexant, to obtain the TrakSmart system. Project implementation commenced early in 2010. Based on the project schedule, the DSMS will be implemented and will be operational by November 2010. The costs associated with implementing and maintaining DSMS will be added to the portfolio level expenditures in 2010. The costs to implement DSMS are $685,000 US and they are included in the Portfolio-level expenditures for 2010.

Once the DSMS is implemented, it will increase the ability of the Companies to capture and report on the following features:

- Program participants' information, costs and energy savings for EEC programs and activities;
- Forecasting / extrapolation based on estimates and actuals;
- Expenses and budget tracking associated with the EEC;
- Interface with SAP[20] application;
- Costs (program, incentive and administrations) associated with EEC projects; and
- Capture of information on a per participant basis i.e. equipment models, reasons for rejection etc.

Once the DSMS is in place and the transition period from the current system to new is completed, these features will help the EEC team to make data gathering, tracking and reporting more efficient and increase the overall efficiency of the workflow.

7.2 Robust Business Case Process Applied to All Programs

Before a new EEC program can be implemented, a program plan or business case must first be developed. The Companies are committed to putting each program through a high level of internal scrutiny before moving ahead with a program, and believe doing so ensures an increased chance of program effectiveness.

The business case developed includes information about program rationale and purpose as well as description of target audience, assumptions, costs-benefit tests and proposed evaluation methods is developed. Cost-benefit analysis is performed using the California Standard Tests ("CST") as outlined in California Standard Practice Manual. In partnership with Willis, the Companies have developed an in-house cost-benefit modelling tool based on CST that provides the following areas of analysis:

- Benefits incurred over measure life of the individual programs; including energy savings over the measure life of the program;
- Total costs incurred in implementing the program including administrative, incentive, marketing and evaluation; and
- The four CST tests (Rate Impact Measure ("RIM"), Utility, Participant and TRC).

The results from this modelling are used as inputs for the business cases, which are approved in accordance with the Companies' policy on financial authorization levels.

[20] System, Applications and Products ("SAP") is a financial tool used by the Companies. All EEC expenditures are captured within SAP.

7.3 Incentive Applications Vetted for Compliance with Program Requirements

Ensuring that all customer applications are compliant with program requirements is also part of the internal control process. The Companies' EEC activity has a number of mechanisms in place to ensure compliance of incentive applications with program requirements.

The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive and other parameters. The general principles applied are as follows:

1. Each application is reviewed for completeness and accuracy.

2. Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process. Please refer to Appendix G for a copy of the Efficient Boiler Program's Terms and Conditions as an example.

3. Once approved, incentives are distributed to participants.

4. Copies of application and supporting documents are filed and stored for seven years in case of an audit.

7.4 Internal Audit Services

The EEC team engaged the Companies own Internal Audit Services ("IAS") group to review the controls associated with the EEC Initiative. Generally speaking, IAS found that there were no major weaknesses in the process and control environment, but that there were minor weaknesses requiring prompt management attention to ensure that the risks identified were mitigated. Management either has already taken action to address IAS' recommendations, or is going to do so as agreed upon on a timely basis.

The primary findings of weaknesses within the controls related to the Companies' EEC initiative are presented and commented upon below:

- Process and internal control documentation for various EEC programs was not readily available. This is true of some of the Companies' long-running initiatives such as the Efficient Boiler Program, however all new programs have process documentation in the Business Case for the Program, and on a go-forward basis, the EEC team will seek input from IAS on controls needed on a program-by-program basis
- Some of the EEC programs are administered by third-parties; however, their performance was not often monitored by the Companies. A periodic review of the effectiveness of third party administrators is recommended to ensure that quality of the program administration is acceptable, and this will be implemented by the EEC team on a go-forward basis
- There was one incident noted by IAS where an application approved did not follow one of the published terms and conditions of a program. The EEC team will ensure that program terms and conditions are followed.

The full report from the Companies' IAS group can be found at Appendix H.

7.5 Summary

The Companies are committed to strong internal controls in all aspects of the EEC Program. As demonstrated in this section, the Companies' business practices related to program development, application processing, and ongoing monitoring are all sound and subject to continuous improvement.

The Companies' EEC team is implementing a robust data gathering and program participation tracking system (the DSMS) in order to accommodate the increased level of EEC activity arising from the funding approval. Expenditures reported through the DSMS will be gathered from SAP, which tracks all of the Companies' financial activity.

All business case and financial approvals are performed in accordance with the Administrative Policy on the Companies' Authorization Levels. There are solid business practices in place related to EEC activity, such as a requirement for a detailed business case for all new programs and initiatives.

The Companies' Internal Audit group has reviewed the processes of the EEC team and while generally the controls related to EEC activity are adequate, there are some areas for improvement that the EEC team either already has addressed, or is in the process of addressing.

In 2010 and beyond the Company will continue to monitor its internal controls and to work with Internal Audit to do the same so that all aspects of the EEC Program are carried out with appropriate diligence and scrutiny.

8. MARKET TRANSFORMATION AND ATTRIBUTION

The Companies' EEC Application outlined a number of Principles that will guide the Companies' EEC activity, one of which is that EEC programs will support Market Transformation. The Companies believe in this mandate and are taking action to ensure that its activities encourage and support Market Transformation.

Moreover, the Utility is playing a leadership role in paving the way for the introduction of Regulated Standards, and believes energy savings resulting from these standards should be attributed to utility programs.

This section outlines the Companies' belief in these two guiding principles, and the actions that are being taken in support of each.

8.1 Committed to Contributing to Market Transformation

The EEC activity around water heaters, whole home initiatives such as labelling and the move to a performance-based building code, and codes and standards work in general, supports market transformation efforts. Utility EEC activity is a key component of Market Transformation efforts.

The Companies have a role to play in preparing the marketplace for the introduction of Regulated Standards. The areas where the Companies could contribute to market transformation include:

- disseminating information;
- educating stakeholders about efficient products, systems, and buildings;
- supporting training related to the design, installation and maintenance of efficient products, systems and buildings;
- addressing price barriers through incentives;
- supporting the development of voluntary measures; and
- advising government on the development of Regulated Standards.

There are a number of EEC initiatives discussed in this report that support Market Transformation, however the most immediate initiative is for domestic hot water, which is discussed below

8.2 Playing a Leadership Role in Market Transformation: Attribution of Savings

Utilities play an integral role in paving the way for the introduction of Regulated Standards. It is because of this key role, the Companies believe that energy savings resulting from regulation should be attributed to utility programs.

In the EEC Application, the Companies proposed a formulaic approach to the attribution of savings from the introduction of minimum energy efficiency performance standards (henceforth referred to as "regulation") to utility market transformation programs. In the EEC Decision, this proposal was rejected, and the Companies were directed to redesign and resubmit a modified proposal for attribution of savings from the introduction of regulation in this report. Further, in its EEC Decision, the Commission noted that:

> *"The Commission Panel accepts the position of BC Hydro that attribution of savings should be considered on a case-by-case basis and that the attribution rate should reflect the level of support for market transformation. The Commission Panel shares the BCSEA/SCBC's concern, as detailed in Mr. Plunkett's evidence, that the attribution concept can distort program design."*[21]

The Commission Panel further directed the Companies to give consideration to factors such as the length of time a particular program element has been operative at the time any applicable regulation is introduced and how compatible the program initiative is with the new regulation (i.e. if a regulation is introduced with a higher or lower threshold or standard than the program design).

8.3 <u>Newly Developed Attribution Model Reflects Industry Best Practices</u>

In the process of developing a modified proposal for attribution of savings from regulation, the Companies reviewed practices in Ontario and consulted with BC Hydro and FortisBC. As a result of the review and consultation, the Companies propose that the attribution of savings from regulation should be considered on a case-by-case basis, consistent with BC Hydro's position. The Companies would propose any cases for attribution from the introduction of regulation in their Annual EEC Report to the Commission.

The information below outlines the Companies' proposal to attribute savings from the introduction of a provincial government regulation requiring condensing water heaters in residential installations in 2013. It is based upon a strategy paper on Condensing Water Heaters written for the Companies by Habart, which is provided in Appendix I.

MEMPR has indicated that in 2013, the minimum efficiency threshold for residential water heaters will be 0.80 EF. In order to reach 0.80 EF, water heater manufacturers will need to use condensing technology. At this time, there are currently no models of condensing water heaters available that are appropriately sized for residential applications. While no pricing information is available on this product, Habart has assumed the incremental cost for a condensing water heater is likely to be approximately $1,750, which makes the technology non-cost-effective for customers.

In support of the government's proposed regulation, the Companies propose implementing a Condensing Water Heater Initiative ("CWHI") to transform the market for residential water heaters. The CWHI consists of a customer purchase incentive of $1,000 along with a fairly significant training and marketing campaign as outlined in Habart's strategy paper in Appendix I. The Companies believe this CWHI would encourage the development of residential condensing

[21] EEC Decision, page 40-41

water heaters by manufacturers, and encourage the uptake of these water heaters by the marketplace. Increased demand will result in incremental manufacturing cost savings through economies of scale and cause lower pricing to the end consumer. The CWHI assumes that this level of activity by the Companies will result in an annual decline of 10% in the cost of Condensing Water Heaters, and increasing penetration of Condensing Water Heaters year over year.

It is the Companies' view that the market transformation process to transform the market for residential domestic hot water to the point where there is sufficient market penetration of 0.80 EF equipment to be able to introduce regulation of 0.80 EF as the minimum efficiency standard will take approximately 7 years.

Without the Companies' activity in this area, it is unlikely that government's proposed regulation will be successful as this technology does not exist today. In order to make this CWHI cost-effective, the Companies would need attribution of 6 years of savings from this particular regulation, which is not unreasonable given that the regulation will not succeed without the Companies' activity to transform this marketplace.

A spreadsheet detailing the benefit-cost scenario for the CWHI can be found in Appendix I.

The proposal above aligns with BC Hydro's policy of attribution on a case-by-case basis, as well as the BCSEA's concerns in that without this Initiative, government's desire to introduce regulation of residential water heaters to 0.80 EF is not likely to succeed.

The Companies are requesting Commission approval of this modified proposal for the attribution of savings from regulation to be on a case-by-case basis. The Companies are also seeking approval to attribute 6 years of post-regulation savings to a market transformation initiative for condensing water heaters.

8.4 Summary

Changing market behaviour and developing Regulated Standards that encourage conservation are both complementary yet critical components of a broader EEC Portfolio. The Companies believe firmly in both principles; they are taking a lead role in promoting market transformation making it possible for government to introduce new standards. Because of this leadership the Companies believe that energy savings resulting from the new standards should be attributed to utility programs. The attribution model put forward in this Report reflects industry best practices and has the confidence of the Companies.

The Companies will continue with their efforts to transform the marketplace while seeking Commission approval of its modified proposal for the attribution of savings on a case-by-case basis.

Appendix A

GLOSSARY

GLOSSARY OF TERMS

ABSU – Accenture Utilities Business Process Outsourcing Services

AFUE – Annual Fuel Utilization Efficiency

AHRI – Air-Conditioning, Heating, and Refrigeration Institute

BC Hydro – British Columbia Hydro and Power Authority

BCUC – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

BTU - British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

CCE – Consortium for Energy Efficiency

CEO – Conservation, Education and Outreach

CHBA – Canadian Home Builders' Association

CHF – Co-operative Housing Federation

CIPH – Canadian Institute of Plumbing and Heating

Commission – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Companies – Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

CPR – Conservation Potential Review, a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

CST – California Standard Tests

CWHI - Condensing Water Heater Initiative

DC – Pacific Resource Conservation Society's Destination Conservation program

DES - District Energy Systems

DHW – Domestic Hot Water

DSM – Demand-Side Management, defined as "any utility activity that modifies or influences the way in which customers utilize energy services". From Terasen Gas' perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

DSMS – Demand Side Management System

ECAP - Energy Conservation Assistance Program

ECM - Electronically Commutated Motors

EEC – Energy Efficiency and Conservation

EEC Application – 2008 Energy Efficiency and Conservation Programs Application

EEC Decision – BCUC Order No. G-36-09

EF – Efficiency Factor

ESK - Energy Savings Kit

FE – Fireplace Efficiency

Forum – Affordable Energy Conservation Forum

Free Rider Rate – percent who would have implemented an EE measure even without the program.

GHGs – Greenhouse Gas Emissions

GJ – Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GSHP – Ground Source Heat Pump

Habart - Habart & Associates

HPBAC – Hearth, Patio & Barbecue Association of Canada

IAS – Internal Audit Services

IRs – Information Requests

IT – Information Technology

KnowledgeTech – KnowledgeTech Consulting Inc.

LEAP – LiveSmart Energy Assistance Program

LIEEPs – Low Income Energy Efficiency Programs

MBH - 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

MEMPR – Ministry of Energy Mines and Petroleum Resources

MOU – Memorandum of Understanding

MURB – Multi-Unit Residential Buildings

MVHC – Metro Vancouver Housing Corporation

NPV – Net Present Value

NRCan – Natural Resources Canada

NSA – Negotiated Settlement Agreement

NSP – Negotiated Settlement Process

O&M – Operating and Maintenance Costs

Participant Test – is the measure of the quantifiable benefits and costs to the customer due to participation in a program.

PBR – Performance Based Rate

PBR Settlement Agreement – Multi-Year Performance Based Rate Plan Settlement Agreement

QDP – Qualified Dealers Program

REnEW - Residential Energy and Efficiency Works

Report – EEC Annual Report

REUS – Residential End Use Survey

RIM – Rate Impact Measure test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

SAP - System, Applications and Products - financial tool in which EEC expenditures are captured within

SEMP - Strategic Energy Management Plan

SENC - Super Efficient New Construction

SHIFT - Sustainability and Social Responsibility Attitudes Study

SPIFF – Sales Promotion Incentive Fund

Strategy Paper - Affordable Energy Conservation Strategy Paper

Task Force – Affordable Energy Conservation Task Force

Team Terasen – Team Terasen Outreach group

Terasen Gas – Terasen Gas Inc, TGI, a subsidiary of Terasen Inc.

TGI – Terasen Gas Inc., a subsidiary of Terasen Inc.

TGI RRA – TGI 2010-2011 Revenue Requirements Application

TGVI – Terasen Gas (Vancouver Island) Inc., a subsidiary of Terasen Inc.

TGVI RRA RDA – TGVI 2010-2011 Revenue Requirements and Rate Design Application

TJ – Terajoule – equal to 1000 gigajoules.

TRC – Total Resource Cost test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

TSS - Technical Sales and Support department

Utility Cost Test – measures the net costs of demand-side management programs as a resource option based on the costs incurred by the utility (including incentive costs) and exclude the net costs incurred by the participant.

Willis – Willis Energy Services

Working Group – BC Working Group for Energy Efficiency for Affordable Housing

Appendix B

DSM REGULATION

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

Ministerial Order No.

M 271

I, Richard Neufeld, Minister of Energy, Mines and Petroleum Resources, order that the attached regulation is made.

DEPOSITED
NOV 7 2008
B.C. REG. 326/2008

Date

November 6, 2008

Minister of Energy, Mines and Petroleum Resources

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (e)

Other (specify):-

November 3, 2008

R/1175/2008/27

DEMAND-SIDE MEASURES REGULATION

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy device" has the same meaning as in the *Energy Efficiency Act*;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems in buildings, or

(d) conduct energy efficiency audits;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) an energy device,

(b) an energy-using product,

(c) a building design, or

(d) thermal insulation;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

"technology innovation program" means a program

(a) to develop a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

Application

2 (1) This regulation applies only with respect to demand-side measures proposed by the authority.

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

Adequacy

3 A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area,

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4 (1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission may include in the benefit a proportion of the benefit that, in the commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

Appendix C

BC ENERGY EFFICIENCY ACT STANDARDS

Appendix C provides the reader with the Provincial regulations pertaining to the two most common Residential gas-fired appliances:

- Forced Air Furnaces – MEMPR Enforcement Bulletin 09-03
- Water Heaters – MEMPR Information Bulletin 09-05

B.C. ENERGY EFFICIENCY ACT STANDARDS:

Gas Furnaces

BRITISH COLUMBIA
The Best Place on Earth

MEMPR ENFORCEMENT BULLETIN 09-03

What products are you regulating? The British Columbia *Energy Efficiency Act (EEA)* Automatic operating gas-fired central forced-air furnaces that use propane or natural gas and have an input rate not exceeding 66 kW (225 000 Btu/h). The regulation applies to residential and commercial furnaces.

Are you forcing me to replace my furnace? No. The regulation only applies to purchases of new or replacement furnaces. Individuals can keep their existing furnaces for as long as they wish.

What is the regulated energy efficiency standard for those products? Such products must achieve an Annual Fuel Utilization Efficiency (AFUE) equal to or greater than 90%, as tested under the standard CSA P.2-07: *Testing Method for Measuring the Annual Fuel Utilization Efficiency of Residential Gas-fired Furnaces and Boilers*. These products are commonly known as "condensing furnaces."

When will the regulations take effect in British Columbia?
For furnaces for new residential construction and all commercial buildings: January 1, 2008.
Replacement furnaces in existing dwellings: December 31, 2009.

Can I sell my inventory of non-compliant products after the effective date? For furnaces for new residential construction, any products manufactured after January 1, 2008 must comply with the regulation.

For replacement furnaces, any products manufactured after December 31, 2009 must comply with the regulation. If you have unsold inventory of products manufactured before the effective date, they can still be sold legally in British Columbia after the effective date.

Are there any exemptions to these regulations? Furnaces for recreational vehicles are exempted from the regulation. The Ministry is also providing an extended timeline for "through the wall' furnaces. A through-the-wall gas furnace is a gas-fired furnace that is designed and marketed to be installed in an opening in an exterior wall that is fitted with a weatherized sleeve. For through-the-wall gas-fired furnaces only, the 90% AFUE standard will come into effect on December 31, 2012.

B.C. ENERGY EFFICIENCY ACT STANDARDS:
Gas Furnaces

BRITISH COLUMBIA
The Best Place on Earth

MEMPR ENFORCEMENT BULLETIN 09-03

How can I tell if a product is compliant with the energy efficiency regulations? Suppliers can demonstrate compliance with the standard by ensuring that the product is listed in the Natural Resources Canada furnace database, and that the database indicates an AFUE equal to, or greater than 90%: www.oee.nrcan.gc.ca/residential/business/manu¬facturers/search/gas-furnace-search.cfm?attr=4

Who enforces this regulation? The Ministry of Energy, Mines and Petroleum Resources is responsible for enforcing all regulated standards under the *EEA*.

What are the penalties for non-compliance? Under the *EEA*, the Ministry can conduct inspections to verify compliance with the *Act* and regulations. *EEA* enforcement begins with education and voluntary compliance measures. Ministry staff follow up on all complaints and other information respecting non-compliance, and communicate directly with industry participants to develop a compliance plan.

The Ministry can also seek to have those who have contravened the legislation charged under the *Offence Act*. An offence can result in fines up to $2,000.

What do I do if I see a non-compliant product for sale or distribution? Please circulate this enforcement bulletin to the retailer or distributor. You can also report infractions to Erik Kaye, Ministry of Energy, Mines and Petroleum Resources at 250-356-1507 or Erik.Kaye@gov.bc.ca

For more information on B.C.'s *Energy Efficiency Act*:
www.empr.gov.bc.ca/EAED/EnergyEfficiency/Pages/EEAct.aspx

Last Updated April, 2009

B.C. ENERGY EFFICIENCY ACT STANDARDS:

Gas and Propane-Fired Water Heaters

BRITISH COLUMBIA
The Best Place on Earth

MEMPR INFORMATION BULLETIN 09-05

What products are you regulating? Storage-type water heaters with a rated storage capacity of 76 to 380 litres and an input of 75 000 Btu/h or less, for use with natural gas or propane.

Are you forcing me to replace my water heater? No. The regulation applies to voluntary purchases of new or replacement water heaters. Individuals can keep their existing water heaters for as long as they wish.

What is the regulated energy efficiency standard for those products?
The Energy Factor (EF) must be greater or equal to[1] :
$0.70 - (0.0005 \times V)$

Here are the new minimum EF levels for several common sizes:

Rated Storage Capacity in litres (US gallons)	Minimum Energy Factor
114 L (30 US gal)	0.64
151 L (40 US gal)	0.62
181 L (48 US gal)	0.61
189 L (50 US gal)	0.61
246 L (65 US gal)	0.58
283 L (75 US gal)	0.56

For a lookup table with all sizes, go to:
www.empr.gov.bc.ca/EAED/EnergyEfficiency/Pages/EEAct.aspx

When will the regulation take effect? September 1, 2010

Can I sell my inventory of non-compliant products after the effective date? Any water heaters manufactured after September 1, 2010 must comply with the regulation. If you have unsold inventory of products manufactured before the effective date, they can still be sold legally in British Columbia after the effective date.

How can I tell if a product is compliant with efficiency regulations? Suppliers can ensure compliance with the standard by stocking only products that meet the minimum EF level outlined above. If the manufacturer's product literature is not clear on this point, Natural Resources Canada has a gas water heater database which lists EF by model number, which can be found at www.oee.nrcan.gc.ca/residential/business/manufacturers/search/gas-water-heaters-search.cfm?attr=4

[1] In this equation, V is the water heater's rated storage capacity in litres, as tested under the standard *CAN/CSA-P.3-04: Testing Method for Measuring Energy Consumption and Determining Efficiencies of Gas-Fired Storage Water Heaters.*

Do ENERGY STAR water heaters meet the new standard?
As of September 1, 2010, all new ENERGY STAR water heaters will be compliant with the B.C. regulation. ENERGY STAR water heaters manufactured before September 1, 2010 may not meet the standard in all cases, please check the database referenced in the previous question to confirm. Note: the ENERGY STAR standard is the same for all water heater sizes, whereas the new B.C. requirements vary with the tank size.

Who enforces this regulation? The Ministry of Energy, Mines and Petroleum Resources is responsible for enforcing all regulated standards under the *EEA*.

What are the penalties for non-compliance? Under the *EEA,* the Ministry can conduct inspections to verify compliance with the *Act* and regulations. *EEA* enforcement begins with education and voluntary compliance measures. Ministry staff follow up on all complaints and other information respecting non-compliance, and communicate directly with industry participants to develop a compliance plan.

The Ministry can also seek to have those who have contravened the legislation charged under the *Offence Act*. An offence can result in fines up to $2,000.

What do I do if I see a non-compliant product for sale or distribution?
Please circulate this information bulletin to the retailer or distributor. You can also report infractions to Erik Kaye, Ministry of Energy, Mines and Petroleum Resources at 250-356-1507 or Erik.Kaye@gov.bc.ca.

For more information on B.C.'s *Energy Efficiency Act*:
www.empr.gov.bc.ca/EEC/Strategy/EEA/Pages/default.aspx

Appendix D

PROGRAM DETAILS

OVERVIEW AND INTRODUCTION

This appendix includes further details not included in Sections 4 and 5 regarding the Companies 2009 and 2010 EEC Portfolio of programs and associated activities. Only when additional details are available, are the programs and associated activities included in this appendix. These details are organized into sections, outlined below:

- Residential Energy Efficiency Programs
- High Carbon Fuel Switching
- Commercial Energy Efficiency Programs
- Conservation, Education, and Outreach Programs
- Enabling Activities
- Pilot Studies (2009)
- Pilot Studies (2010)

The function of this appendix is to provide the reader with information pertaining but not limited to program background, objectives, target market, research methodology, detailed findings, etc.

TABLE OF CONTENTS

RESIDENTIAL ENERGY EFFICIENCY PROGRAMS

Details of the Residential Energy Efficiency Programs are described in this section. These programs include:

- ENERGY STAR® Heating System Upgrade Program
- EnerChoice Fireplace Program
- ENERGY STAR® Domestic Hot Water Heaters Program

PROGRAM: ENERGY STAR® HEATING SYSTEM UPGRADE PROGRAM

Program Area: Residential Energy Efficiency

Target Market: Retrofit

Duration: TGI: September 1, 2008 through December 31, 2009
TGVI: April 16, 2009 through December 31, 2009

Incentive: $250 bill credit

Program Objectives:

- Prepare market for adoption of ENERGY STAR® provincial furnace regulations for retrofit market, January 1, 2010
- Upgrade a minimum of 8,180 heating systems
- Educate trades community about upcoming regulations
- Educate consumers about the advantages of energy efficient furnaces and boilers and provide an incentive that promotes a proactive replacement decision
- Engage manufacturers by distributing coupons for ENERGY STAR® furnaces and boilers and providing funds for co-marketing opportunities
- Develop a cost effective program with TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs

Partner: LiveSmart BC Residential Retrofit Incentive Initiative

Communications Plan:

The following initiatives were implemented to provide consumer awareness and engagement by the trades community and manufacturers.

- www.terasengas.com – included program information, application forms and program terms and conditions. The site included manufacturer coupons for download from September through December 2008, and September through December 2009.
- Bill inserts with program information and instructions for downloading coupons
- Contractor brochures, Point of Sale information, distributed to BC Safety Authority registered gas contractors
- Information distributed to all customer touch points including call centres and sales and service staff
- Co-op advertising funds reimbursed participating manufacturers' or their dealers 50 per cent of their media print advertising costs to support their ENERGY STAR® heating systems advertisements
- Program information was distributed at all trade shows and Team Terasen events

Program Administration:

Program administration was handled by Accenture Utilities Business Process Outsourcing Services ("ABSU"), a subsidiary of Accenture Inc., through a subcontracting arrangement with CustomerWorks LP. The program administration costs invoiced in 2009 were $60,000. ABSU handled data entry for applications, validation of ENERGY STAR® rated heating systems, the batch process that administered the $250 bill credit, customer support, and reporting. To receive the bill credit, customers were required to submit their completed application and a photocopy of the furnace invoice, including the installation date, the contractor's BC Safety Authority registration number, and the gas permit installation number.

LiveSmart BC Partnership:

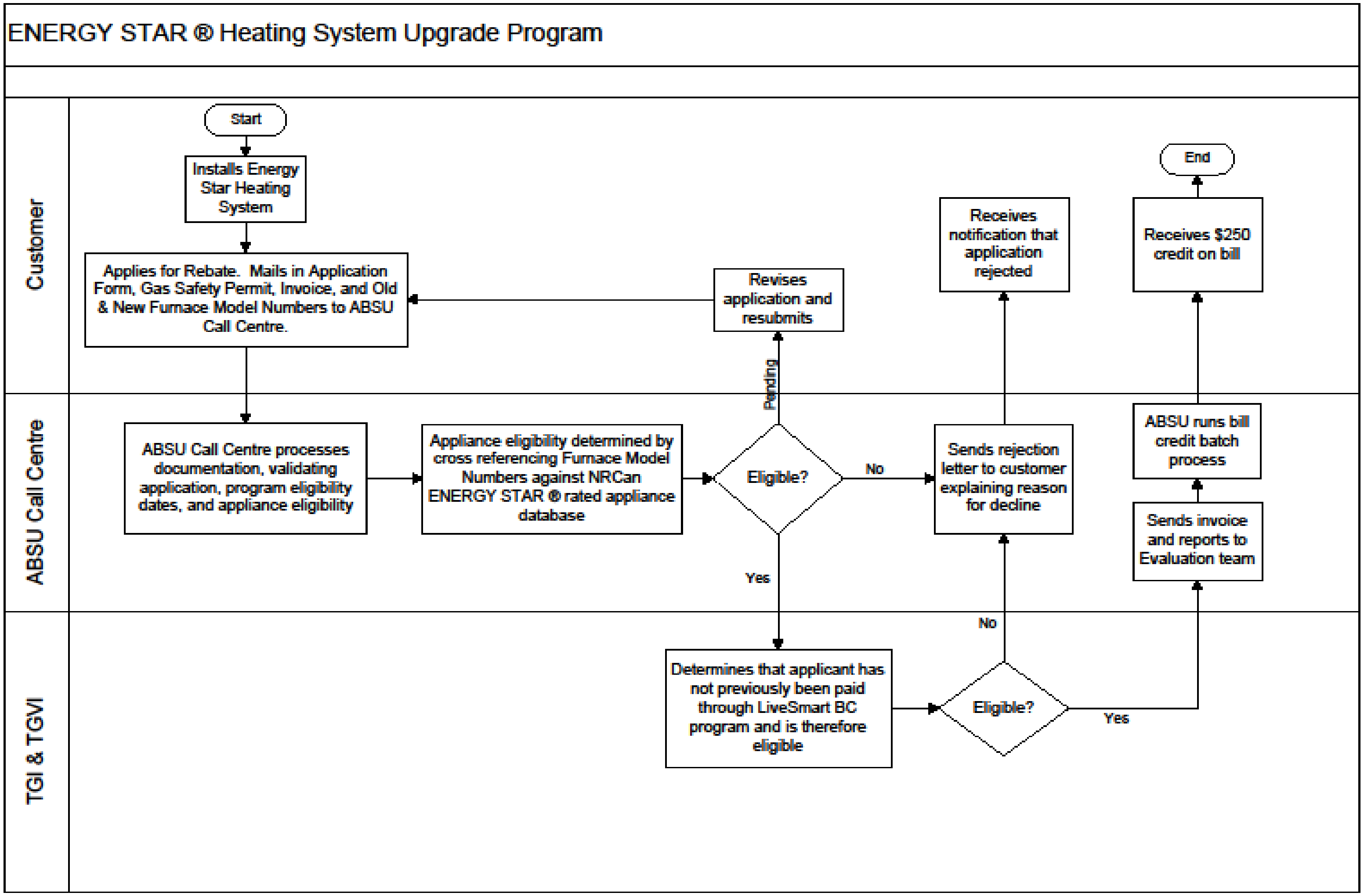
There were two channels for customers to receive the Companies' $250 ENERGY STAR® Heating System incentive. TGI and TGVI customers could apply directly to the Companies for the incentive or alternatively complete a home energy assessment through the LiveSmart BC program to receive the $250 incentive paid out through a cheque from LiveSmart BC.

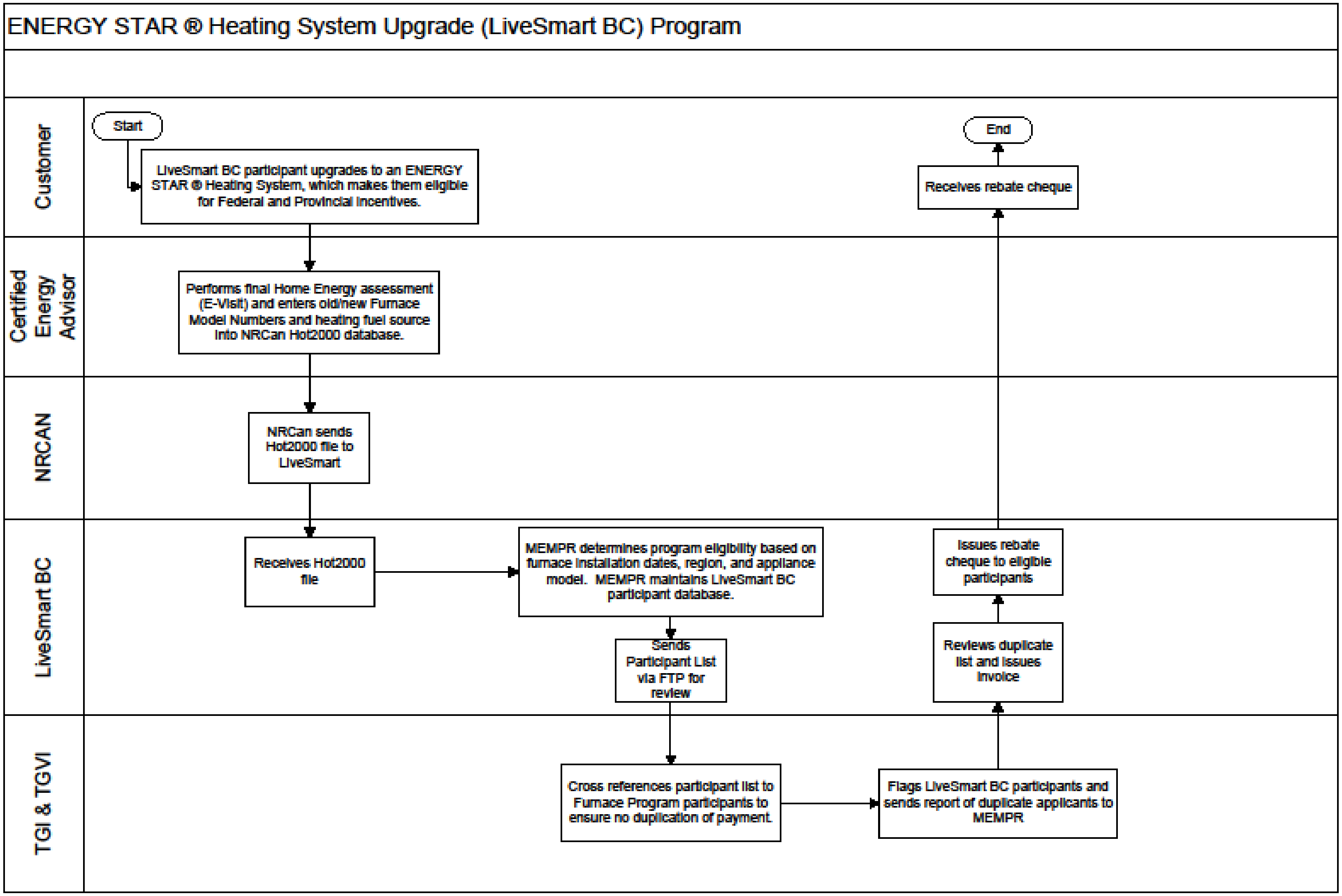
The LiveSmart BC Residential Retrofit Incentive Initiative, launched in May 2008 by the Provincial government, provided incentives to reward residential retrofits that saved energy and reduced GHGs. As part of the Energy Efficient Buildings Strategy, the goal was to create a one-stop shop to provide homeowners with coordinated, easy access to utility, provincial, and federal incentives Data-gathering for the LiveSmart partnership was completed through NRCan ecoENERGY Home Renovation program. In order to receive these incentives, homeowners had to complete both a pre (D-visit) and post-retrofit (E-Visit) home energy assessment with a Certified Energy Advisor, licensed by NRCan[1]. At the time of the Home Energy Assessment, Certified Energy Advisors input data into NRCan's Hot 2000 software, and data files are transferred from NRCan to LiveSmart BC for program administration.

The LiveSmart BC portfolio matched or exceeded federal incentives with the inclusion of funding from BC utility partners, TGI, TGVI, BC Hydro and FortisBC. LiveSmart BC participants who upgraded their heating systems could receive up to $790 in federal funding and $1130 in provincial funding for select ENERGY STAR® heating systems. Of the $1130 in provincial funding, $250 was provided by the Companies, through an August 2008 agreement with MEMPR to include the $250 ENERGY STAR® Heating System incentive within the LiveSmart BC portfolio.

To ensure that customers received only one $250 furnace incentive payment, the Companies developed a cross-checking process between LiveSmart BC participants and the Companies' Heating System Upgrade participants. LiveSmart BC participant lists were sent bi-monthly via a secure file transfer protocol. The LiveSmart BC list was cross-referenced with program to date participants prior to authorizing payment by LiveSmart BC. LiveSmart BC participants were then flagged within the Companies' customer database to eliminate duplicate payment through the bill credit process.

[1] Home Energy Assessments for existing homes are provided by NRCan-certified Home Energy Advisors. The initial assessment is referred to as the D-visit and includes a detailed evaluation of the home's energy efficiency levels, as well as various tests to determine air leaks and recommendations for retrofits that will improve the home's energy efficiency rating. The second visit, referred to as the E-visit, measures energy performance after the recommended retrofits have been completed.


ENERGY STAR ® Heating System Upgrade Program
Customer
ABSU Call Centre
TGI & TGVI
Start
Installs Energy Star Heating System
Applies for Rebate. Mails in Application Form, Gas Safety Permit, Invoice, and Old & New Furnace Model Numbers to ABSU Call Centre.
ABSU Call Centre processes documentation, validating application, program eligibility dates, and appliance eligibility
Appliance eligibility determined by cross referencing Furnace Model Numbers against NRCan ENERGY STAR ® rated appliance database
Eligible?
Pending
Revises application and resubmits
No
Yes
Sends rejection letter to customer explaining reason for decline
Receives notification that application rejected
Determines that applicant has not previously been paid through LiveSmart BC program and is therefore eligible
Eligible?
No
Yes
Sends invoice and reports to Evaluation team
ABSU runs bill credit batch process
Receives $250 credit on bill
End


ENERGY STAR ® Heating System Upgrade (LiveSmart BC) Program
Customer
Certified Energy Advisor
NRCAN
LiveSmart BC
TGI & TGVI
Start
LiveSmart BC participant upgrades to an ENERGY STAR ® Heating System, which makes them eligible for Federal and Provincial incentives.
Performs final Home Energy assessment (E-Visit) and enters old/new Furnace Model Numbers and heating fuel source into NRCan Hot2000 database.
NRCan sends Hot2000 file to LiveSmart
Receives Hot2000 file
MEMPR determines program eligibility based on furnace installation dates, region, and appliance model. MEMPR maintains LiveSmart BC participant database.
Sends Participant List via FTP for review
Cross references participant list to Furnace Program participants to ensure no duplication of payment.
Flags LiveSmart BC participants and sends report of duplicate applicants to MEMPR
Reviews duplicate list and issues invoice
Issues rebate cheque to eligible participants
Receives rebate cheque
End

PROGRAM: ENERCHOICE FIREPLACE PROGRAM

Program Area: Residential Energy Efficiency

Target Market: Retrofit

Duration: TGI and TGVI: Sep 1, 2009 through Dec 31, 2009

Incentive:
- Dealer - $50 SPIFF for each fireplace sold
- Manufacturer Coupons

Program Objectives:

- Encourage the sale and installation of energy efficient heater style fireplaces to reap the associated energy savings.
- Further the education and awareness of the EnerChoice label to consumers and industry.
- Further relationships with manufacturers and distributors of natural gas fireplaces, through the Hearth, Patio & Barbecue Association of Canada.
- Engage manufacturers by distributing coupons for EnerChoice fireplaces
- Develop a cost effective program with TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs

Partner: Hearth Patio and Barbecue Association of Canada ("HPBAC")

Communications Plan:

The 2009 EnerChoice Fireplace program had two marketing components:

- promoting manufacturer coupons to residential customers,
- providing a $50 SPIFF to retail sales personnel for each EnerChoice Fireplace they sold between September 1, 2009 and December 31, 2009.

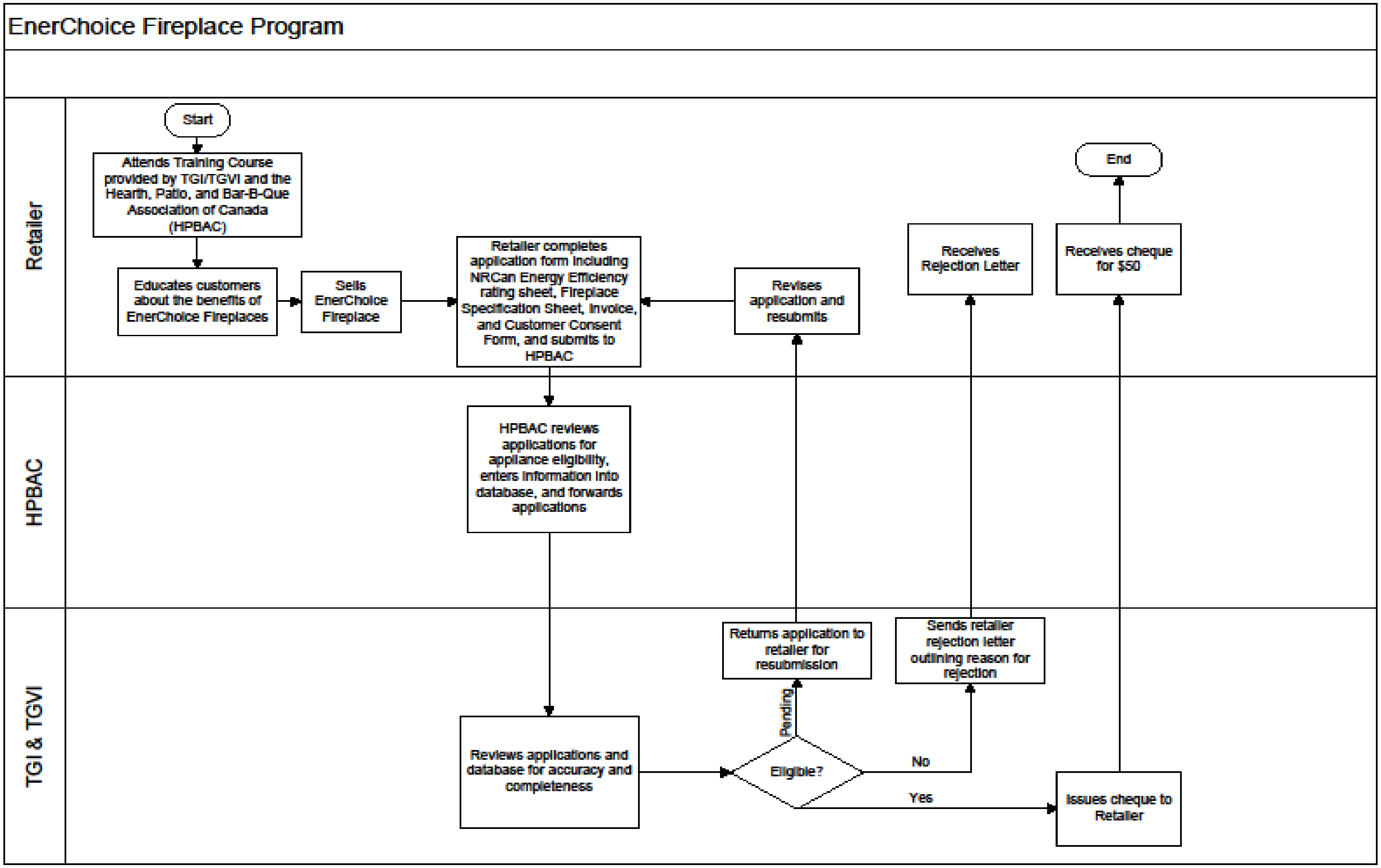
The following initiatives were implemented to provide consumer awareness and engagement by fireplace dealers and manufacturers.

- www.terasengas.com – The site included manufacturer coupons for download from September through October 2008 and September through October 2009
- Bill inserts with program information and instructions for downloading coupons
- Contractor brochures, Point of Sale information, distributed to HPBAC members
- Information distributed to all customer touch points including call centres and sales and service staff
- Community newspaper ads for x weeks in September
- Program information was distributed at all trade shows and Team Terasen events

Program Administration:

The HPBAC provided program administration services for SPIFFS including data entry and validation of supporting documentation including Natural Resource Canada Energy Efficiency Ratings for the fireplace model sold. The EEC team reviewed all documentation and approved applicants for payment.

To be eligible for the $50 SPIFF, retailers were required to attend an online training course on EnerChoice fireplaces, provided by the Companies. In addition, breakfast meetings for fireplace dealers were held on TGVI in August 2009.


EnerChoice Fireplace Program
Retailer
HPBAC
TGI & TGVI
Start
Attends Training Course provided by TGI/TGVI and the Hearth, Patio, and Bar-B-Que Association of Canada (HPBAC)
Educates customers about the benefits of EnerChoice Fireplaces
Sells EnerChoice Fireplace
Retailer completes application form including NRCan Energy Efficiency rating sheet, Fireplace Specification Sheet, Invoice, and Customer Consent Form, and submits to HPBAC
Revises application and resubmits
Receives Rejection Letter
Receives cheque for $50
End
HPBAC reviews applications for appliance eligibility, enters information into database, and forwards applications
Reviews applications and database for accuracy and completeness
Eligible?
Pending
No
Yes
Returns application to retailer for resubmission
Sends retailer rejection letter outlining reason for rejection
Issues cheque to Retailer

PROGRAM: ENERGY STAR® DOMESTIC HOT WATER HEATERS PROGRAM

Program Area: Residential Energy Efficiency

Target Market: Retrofit

Duration: TGI & TGVI: May 1, 2010 through April 1, 2011

Incentive:
- $50 rebate cheque for consumer
- $50 rebate cheque for contractor

Program Objectives:

- Educate the market about the introduction of provincial regulations on September 1, 2010
- Educate consumers about ENERGY STAR® water heaters and the importance of hot water conservation
- Upgrade a minimum of 3600 Hot Water Heaters
- Promote contractor relations between the Companies and contractors, as well as between contractors and customers
- Engage manufacturers and distributors through co-marketing opportunities
- Engage manufacturers in labeling tanks for Efficiency Factor

Communications Plan:

The following initiatives will be implemented to provide consumer awareness and engagement by the trades community and manufacturers.

- www.terasengas.com – will include tile ads and program information, application form for downloading, and program terms and conditions
- Online Manufacturer-driven directory of eligible ENERGY STAR® (or equivalent) hot water tank models
- Bill inserts with program information and instructions for downloading application forms
- Brochure: 3 panel brochure with application form/terms and conditions
- Contractor brochures, point of sale information, distributed to BC Safety Authority registered contractors
- Information distributed to all customer touch points including call centres and sales and service staff
- Tile ads for third party websites and other online opportunities
- Rebate cheque insert with energy saving tips.

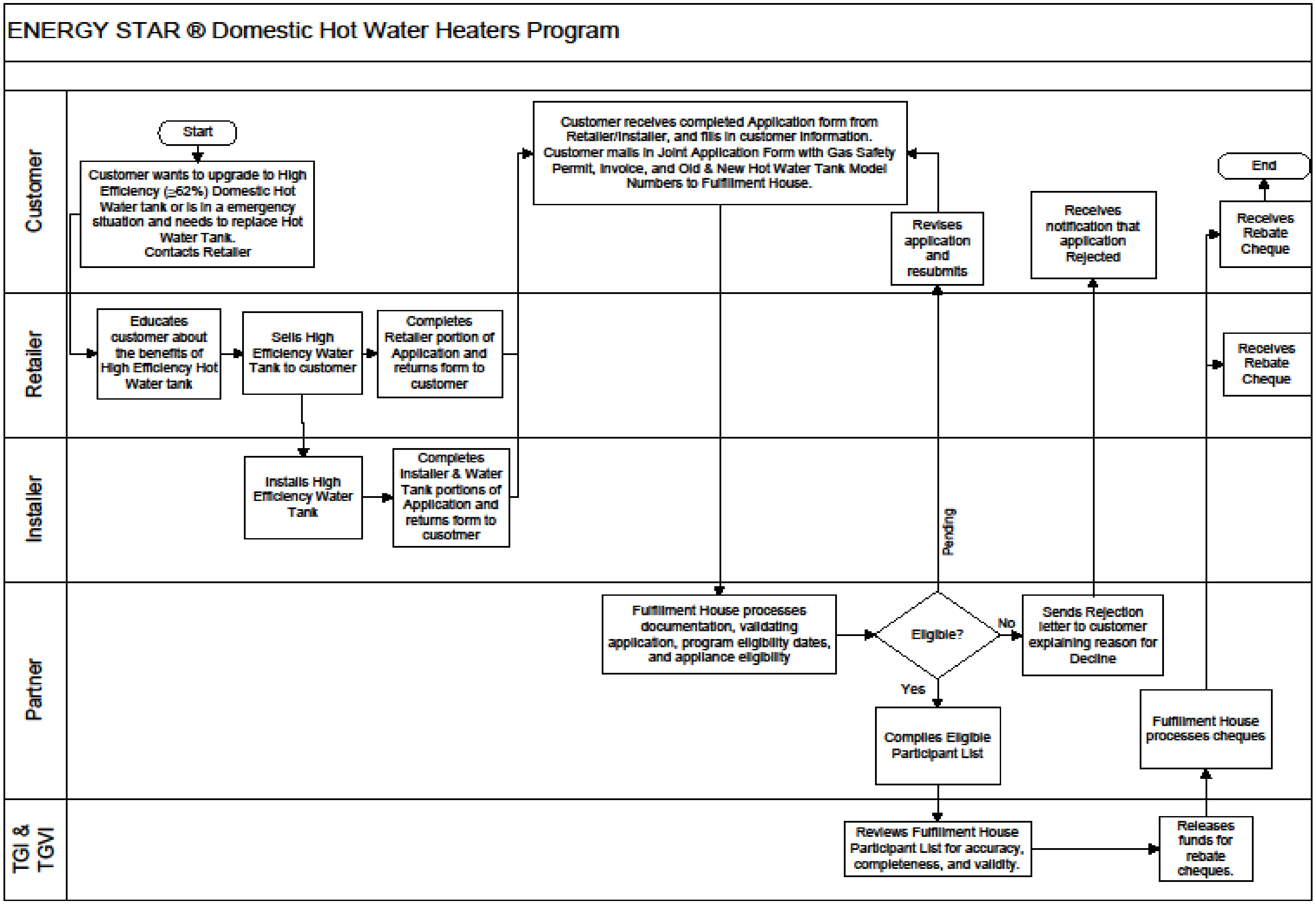
Program Administration:

Program administration will be handled by Consumer-Response Marketing Ltd (CRM). CRM will complete data entry for applications, validation of ENERGY STAR® (or equivalent) hot water tanks, cheque cutting, customer support, and reporting.

The $100 rebate will be split into two incentives:

- a $50 direct to consumer incentive
- a $50 Point of Sale Incentive Fund ("SPIFF") distributed to the sales person who has had contact with the customer to influence the purchase of High Efficiency water tanks

Using a combined incentive application form, consumers will apply for the $50 consumer incentive and at the same time the point of sale contact can apply for their $50. This will help drive the relationship between consumers, trades and retailers. The combined incentive will help streamline the administrative process and eliminate fraud from SPIFF applications.


ENERGY STAR ® Domestic Hot Water Heaters Program
Customer
Retailer
Installer
Partner
TGI & TGVI
Start
Customer wants to upgrade to High Efficiency (≥62%) Domestic Hot Water tank or is in a emergency situation and needs to replace Hot Water Tank. Contacts Retailer
Educates customer about the benefits of High Efficiency Hot Water tank
Sells High Efficiency Water Tank to customer
Completes Retailer portion of Application and returns form to customer
Installs High Efficiency Water Tank
Completes Installer & Water Tank portions of Application and returns form to cusotmer
Customer receives completed Application form from Retailer/Installer, and fills in customer information. Customer mails in Joint Application Form with Gas Safety Permit, Invoice, and Old & New Hot Water Tank Model Numbers to Fulfillment House.
Fulfillment House processes documentation, validating application, program eligibility dates, and appliance eligibility
Eligible?
Pending
Yes
No
Revises application and resubmits
Sends Rejection letter to customer explaining reason for Decline
Receives notification that application Rejected
Compiles Eligible Participant List
Reviews Fulfillment House Participant List for accuracy, completeness, and validity.
Releases funds for rebate cheques.
Fulfillment House processes cheques
Receives Rebate Cheque
Receives Rebate Cheque
End

HIGH CARBON FUEL SWITCHING PROGRAM

Details of the High Carbon Fuel Switching Program is described in this section. This includes:

- Switch 'N' Shrink Program

PROGRAM: SWITCH 'N' SHRINK PROGRAM – OIL CONVERSIONS TO NATURAL GAS ENERGY STAR® HEATING SYSTEM UPGRADES

Program Area: Residential Energy Efficiency Program

Target Market: Retrofit

Duration: January 1, 2010 to December 31, 2010 with possible extension

Consumer Incentive:

- $1,000 rebate cheque for oil or propane conversion
- $50 rebate cheque for Electronically Commutated Motors ("ECM") from BC Hydro or FortisBC

Objectives:

Provide a $1,000 incentive to encourage homeowners to convert their primary heating system from higher carbon oil or propane to a high efficiency natural gas heating system
Upgrade a minimum of 750 homes
Develop relationships with associations for co-marketing opportunities, for example; BC Insurance Brokers Association, real estate associations, environmental groups
Work with MEMPR to include this program as part of the provincial greenhouse gas reduction strategy
Develop a cost effective program with TRC > 1 and maximize the proportion of incentives over administration and marketing costs

Communications Plan:

Promotional initiatives and budget will be focused on the TGVI service area, representing 70 per cent of the projected conversions. The Companies will adopt an integrated marketing approach with program-specific media communications initiatives, contractor communications, co-marketing, and promotion by internal stakeholders such as the customer service centre and TGI/TGVI sales and service staff. Media initiatives include print ads in select trade publications in early 2010 with a summer launch prior to the fall furnace installation peak period.
The following initiatives were implemented to provide consumer awareness and engagement by the trades community and manufacturers.

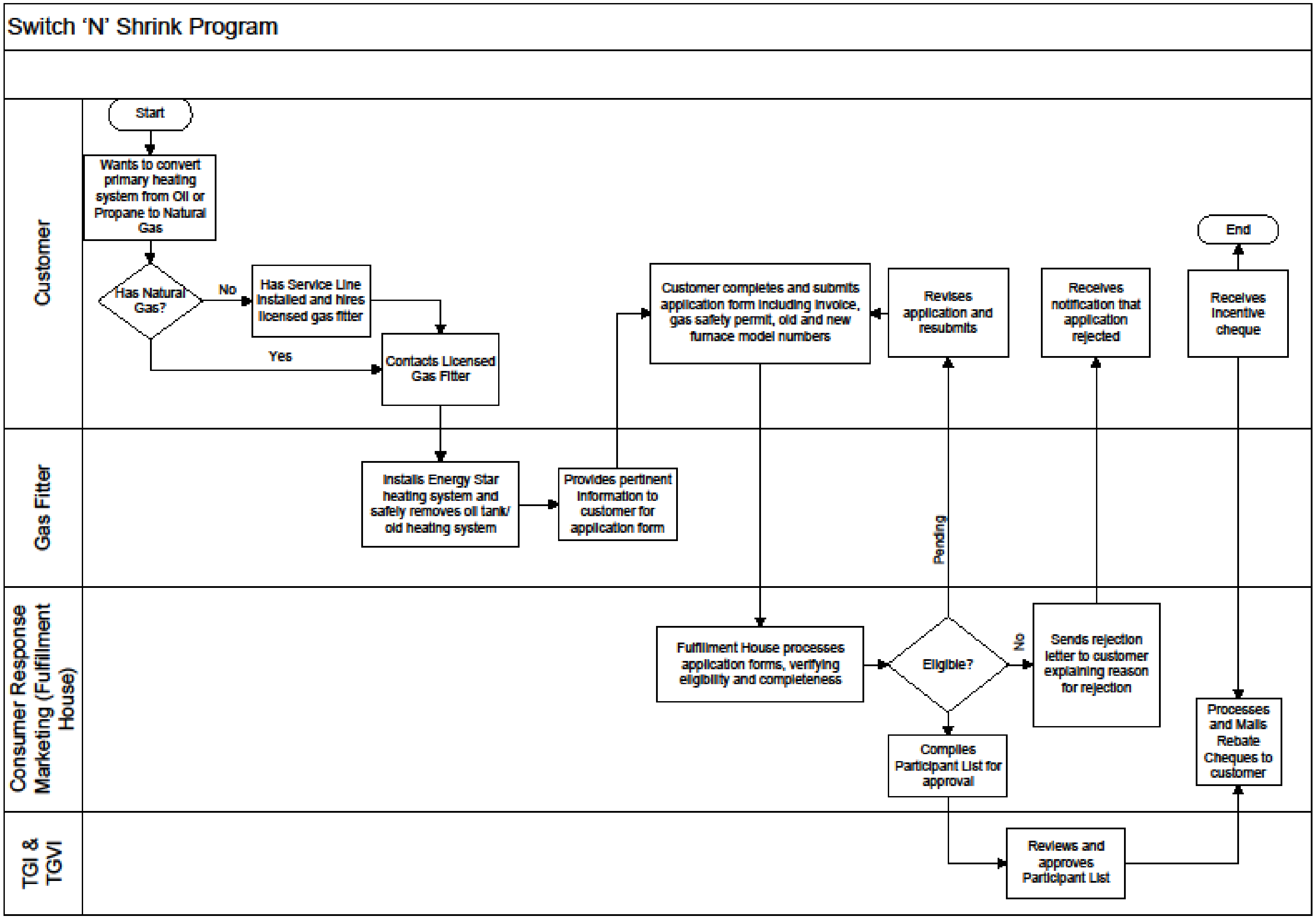
- www.terasengas.com – included program information, application forms and program terms and conditions.
- Contractor Frequently Asked Questions "FAQ's" and application forms were distributed to BC Safety Authority registered gas contractors.
- Information distributed to all customer touch points including call centres and sales and service staff.
- Program information will be distributed at all trade shows and Team Terasen events.

- TGVI Print and radio ads in the summer of 2010 to coincide with conversions prior to the fall peak furnace installation period.
- Print and online ads in trade magazines and building association newsletters.

Co-marketing opportunities with associations include reaching out to associations that are affected by the environmental hazards associated with oil tanks. TGVI is working on developing a promotion with Vancouver Island Insurance Brokers Association to brokers and a DM piece to their customers who heat with oil. Real estate associations and environmental organizations will be contacted to help promote this program.

Program Administration:

Program administration is being outsourced to Consumer Response Marketing (“CRM”), a Surrey-based fulfillment house with extensive experience in rebate administration for DSM programs. CRM will manage data entry of applications, validation of ENERGY STAR® rated heating systems and eligibility for the $50 ECM program (BC Hydro / FortisBC), cheque fulfillment, customer support, and monthly program performance reporting. To receive the incentive, customers are required to submit their completed rebate application, and a photocopy of the furnace invoice, including the installation date, the contractor’s BC Safety Authority registration number, and the gas permit installation number.


Switch 'N' Shrink Program
Customer
Gas Fitter
Consumer Response Marketing (Fulfillment House)
TGI & TGVI
Start
Wants to convert primary heating system from Oil or Propane to Natural Gas
Has Natural Gas?
No
Yes
Has Service Line installed and hires licensed gas fitter
Contacts Licensed Gas Fitter
Installs Energy Star heating system and safely removes oil tank/ old heating system
Provides pertinent information to customer for application form
Customer completes and submits application form including invoice, gas safety permit, old and new furnace model numbers
Revises application and resubmits
Receives notification that application rejected
Receives incentive cheque
End
Fulfillment House processes application forms, verifying eligibility and completeness
Eligible?
Pending
No
Sends rejection letter to customer explaining reason for rejection
Compiles Participant List for approval
Processes and Mails Rebate Cheques to customer
Reviews and approves Participant List

COMMERCIAL ENERGY EFFICIENCY PROGRAMS

Details of the Commercial Energy Efficiency Programs are described in this section. These programs include:

- Efficient Boiler Program
- Light Commercial ENERGY STAR® Boiler Program
- Energy Assessment Program
- Efficient Water Heater Program

PROGRAM: EFFICIENT BOILER PROGRAM

Program Area: Commercial Energy Efficiency

Target Market: New Construction / Retrofit

Duration: TGI: 2005 – December 31, 2011
TGVI: 2005 – December 31, 2011

Incentive:

Participants are incented to purchase high efficiency boilers by a purchase price rebate. This rebate is designed to offset a significant portion of the incremental cost premium associated with purchasing high vs. standard efficiency equipment. Purchase price incentives are:

- Near-condensing boilers: $4,000 per boiler plus $3 per MBH[2] plant input
- Condensing boilers: $6,000 per boiler plus $9 per MBH plant input

For new construction participants the program offers:

1. A maximum incentive payment (calculated as noted above) of up to 75 per cent of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input.
2. An incentive payment of 50 per cent of a consultant's fees to a maximum $1500 to offset the cost of analyzing the annual gas usage for space heating using a standard-efficiency boiler system versus a higher efficiency boiler system.

For retrofit participants the program offers:

1. A maximum incentive payment (calculated as noted above) of up to 50 per cent of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input.
2. An incentive payment of $400 to help offset the cost of engaging a contractor to accurately estimate the peak space-heating load.
3. Where stainless steel venting is installed, an incentive of 50 per cent of the cost up to $2000.
4. For participants who so choose, a monitoring incentive of $1,500 plus $1 per gigajoule (GJ) of energy saved for closely monitoring and reporting on boiler operation and efficiency during the first year of operation.

Program Objectives:

- Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency boilers for space heating.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate medium to large commercial customers about the advantages of high efficiency boilers and provide an incentive to facilitate the purchase of high efficiency technology.

[2] Note: 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

- Maintain a program TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs.
- Support and prepare the way for any provincial regulation requiring increased boiler efficiency.

Communications Plan:

2009 saw the following communications initiatives aimed at raising customer awareness and encouraging program participation.

- www.terasengas.com – All program information, application forms and program terms and conditions were maintained on the Efficient Boiler Program web page.
- Program brochures describing the program specifics and how to apply were handed out at tradeshows.
- Contractor information / presentation sessions put on in August of 2009 in Victoria, Nanaimo and Courtney on Vancouver Island. The EBP was presented and program collateral made available.
- Speaking engagements / presentations describing the program at events such as:
  - BC Apartment Owners and Managers Association Semi-Annual trade show
  - Two (2) NRCan “Spot the energy savings” workshops
  - BC Hydro Power Smart forum
  - BH Hydro Energy managers training session
  - Vancouver Coastal Health and Fraser Valley Health Authority session on energy efficiency and incentive opportunities
- Information distributed to all customer touch points including call centres and sales and service staff.

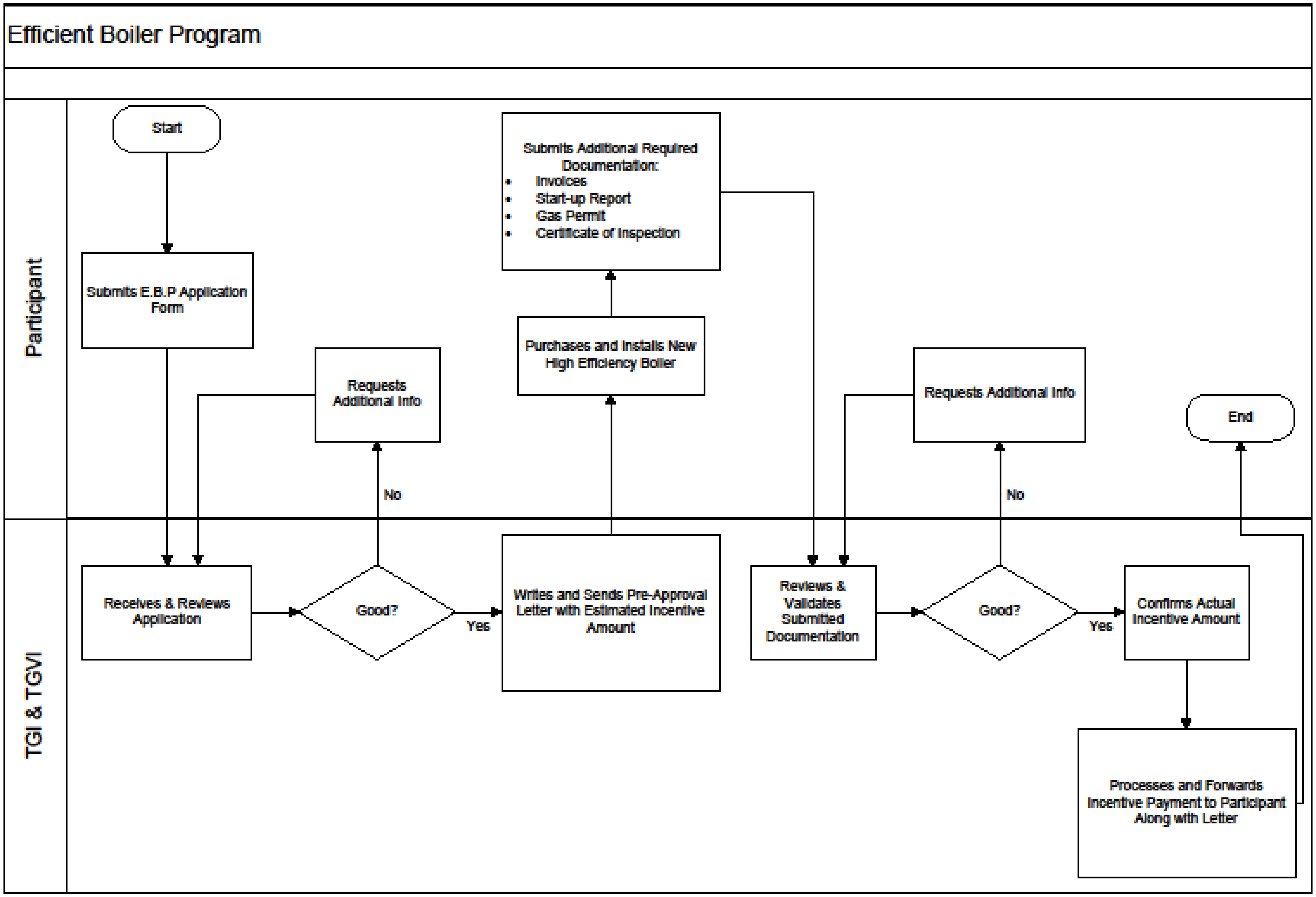
The communications plan for 2010 will reflect what the Companies have learned in 2009, specifically, that additional effort must be expended on both Vancouver Island and in the New Construction arena. The Companies plan on holding a stakeholder focus group and feedback session in late April or early May to gain insight as to how the program may be updated to serve the market better. A full scale communications plan for the Efficient Boiler Program will be developed subsequently.

Program Administration:

Administration of the Efficient Boiler Program is handled entirely in-house by the Companies’ EEC Staff as of January 1, 2010.

For new participants, the Companies’ EEC staff receive applications, input data for program tracking, validate submitted information, ensure all boilers listed on applications are eligible for an incentive, prepare an incentive estimate, process and forward incentive cheques, and guide participants through the application process via on-going telephone support where / when necessary.

Additionally the Companies’ EEC staff responds to all phone or email enquires about the program from potential applicants.


Efficient Boiler Program
Participant
TGI & TGVI
Start
Submits E.B.P Application Form
Requests Additional Info
Submits Additional Required Documentation:
• Invoices
• Start-up Report
• Gas Permit
• Certificate of Inspection
Purchases and Installs New High Efficiency Boiler
Requests Additional Info
End
No
No
Receives & Reviews Application
Good?
Yes
Writes and Sends Pre-Approval Letter with Estimated Incentive Amount
Reviews & Validates Submitted Documentation
Good?
Yes
Confirms Actual Incentive Amount
Processes and Forwards Incentive Payment to Participant Along with Letter

PROGRAM: LIGHT COMMERCIAL ENERGY STAR® BOILER PROGRAM

Program Area: Commercial Energy Efficiency

Target Market: New Construction / Retrofit

Duration: TGI: August, 2009 – December 31, 2011
TGVI: August, 2009 – December 31, 2011

Consumer Incentive:

Boilers must be ENERGY STAR® rated near-condensing or condensing gas boilers sized up to a maximum size of 299 MBH input, and be used primarily for hydronic space and water heating. The incentive is calculated based on the quantity, size and type of boiler as follows:

- Condensing boilers: $5 per MBH, provided that the condensing boiler is used for radiant heat, fan coils and/or domestic water heating (in combination with space heating)
- Near condensing boilers: $3 per MBH
- Sample calculation: 1 MBH is equal to 1,000 BTU's per hour, therefore a 299 MBH or 299,000 Btu/hr condensing boiler would be eligible for a $1495 rebate (299 MBH x $5 = $1,495)

The incentive is independent of the price of boilers or the total cost of the mechanical system. The program does not include any additional rebate or incentive for labour, vent modifications, piping changes, design calculations, or other equipment.

Program Objectives:

- Reduce commercial sector gas consumption by encouraging the installation and use of high efficiency (ENERGY STAR® rated) as opposed to standard efficiency boilers for space heating.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate small to medium commercial customers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary.
- Engage the trades community and manufacturers by supporting new, energy efficient technologies.
- Maintain a program TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs.
- Support and prepare the way for any provincial regulation requiring increased boiler efficiency.

Communications Plan:

2009 saw the following communications initiatives aimed at raising customer awareness and encouraging program participation.

- www.terasengas.com – All program information, application forms and program terms and conditions were maintained on the Light Commercial ENERGY STAR® Boiler Program web page.
- Program brochures describing the program specifics and how to apply were handed out at tradeshows.
- Program brochures and cards describing the program specifics and how to apply were distributed to regional sales / operations centres and sales and service staff.
- Approximate combined total of 2000 pieces of cardstock / brochures distributed.
- Contractor information / presentation sessions put on in August of 2009 in Victoria, Nanaimo and Courtney on Vancouver Island. The Light Commercial ENERGY STAR® Boiler Program was presented and program collateral made available.
- Speaking engagements / presentations describing the program at events such as:
    - BC Apartment Owners and Managers Association Semi-Annual trade show
    - Two (2) NRCan "Spot the energy savings" workshops
    - BC Hydro Power Smart forum
    - BC Hydro Energy managers training session
    - Vancouver Coastal Health and Fraser Valley Health Authority session on energy efficiency and incentive opportunities
- The program was advertised in ASHRAE BC's November 2009 edition of its "Totem" magazine.

2010 will see a sustained and enhanced effort at program promotion. The Companies are currently in the process of developing a strategic communication plan for the Light Commercial ENERGY STAR® Boiler Program which, over and above the activities of 2009, should include:

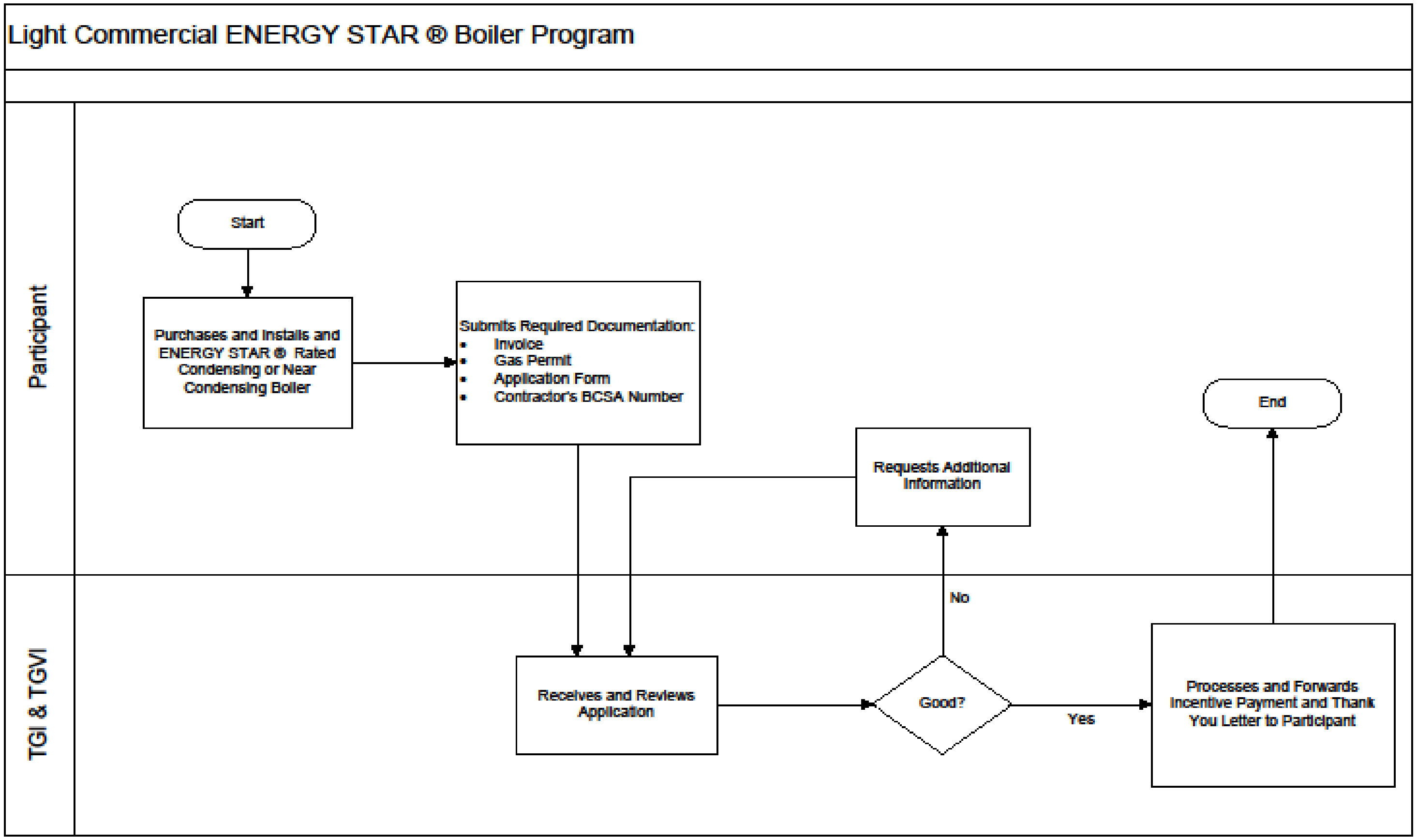
- Direct email advertising
- Additional, targeted magazine/newsletter advertising
- On-bill advertising to rate 2 and rate 3 customers
- Contractor and engineer information sessions
- Additional information sessions on Vancouver Island.
- More leveraging of industry partner relationships
- A program feedback session with key stakeholders

Program Administration:

Administration of the Light Commercial ENERGY STAR® Boiler Program is handled entirely in-house by the Companies' DSM Staff.

For new participants, the Companies' DSM staff receive applications, input data for program tracking, validate submitted information, ensure all boilers listed on applications are ENERGY STAR® rated, process and forward incentive cheques, and guide participants through the application process via on-going telephone support where / when necessary.

Additionally the Companies' DSM staff also responds to all phone or email enquires about the program from potential applicants.


Light Commercial ENERGY STAR ® Boiler Program
Participant
TGI & TGVI
Start
Purchases and Installs and ENERGY STAR ® Rated Condensing or Near Condensing Boiler
Submits Required Documentation:
• Invoice
• Gas Permit
• Application Form
• Contractor's BCSA Number
Requests Additional Information
End
Receives and Reviews Application
Good?
No
Yes
Processes and Forwards Incentive Payment and Thank You Letter to Participant

PROGRAM: ENERGY ASSESSMENT PROGRAM

Program Area: Commercial Energy Efficiency

Target Market: Retrofit

Duration: TGI: 2001 – December 31, 2011
TGVI: 2001 – December 31, 2011

Incentive:

For customers who consume in excess of 2000 GJ per year the Companies, will provide a free, walkthrough energy assessment – a $1200 value.

The walkthrough assessment is performed by a third party energy efficiency consultant retained by Terasen Gas. The consultant visits the participant's facility in order to review current sources of energy consumption and propose measures to reduce consumption. Results are provided to the participant and Terasen Gas in report form, and generally include the following information:

- Historic annual gas usage breakdown by type, i.e., space heating, water heating, process heat
- Readily implemented recommendations such as: using electronic controls to operate boilers and ventilation fans only when needed; insulating all bare heating pipes, valves and flanges in mechanical rooms and unheated areas
- Recommendations regarding upgrades to space, domestic water and process equipment
- Tables to illustrate monthly gas consumption over a one-year period, against monthly gas consumption projections if recommended upgrades are implemented
- Estimated payback periods for each implemented measure
- Information about available rebates or incentives

Program Objectives:

- Enable and encourage commercial customers to reduce gas consumption by identifying sources of high gas consumption within their facilities and proposing measures to reduce consumption.
- Educate commercial customers about gas use within their own facilities and the steps they can take to minimize consumption.
- Foster a culture of conservation among commercial sector customers (including MURBs, institutional and manufacturing customers) by assisting them to review their energy consumption critically.
- Where applicable, direct participants to available incentive programs including Terasen's existing boiler programs.
- Maintain a program TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs

Communications Plan:

2009 saw the following communications initiatives:

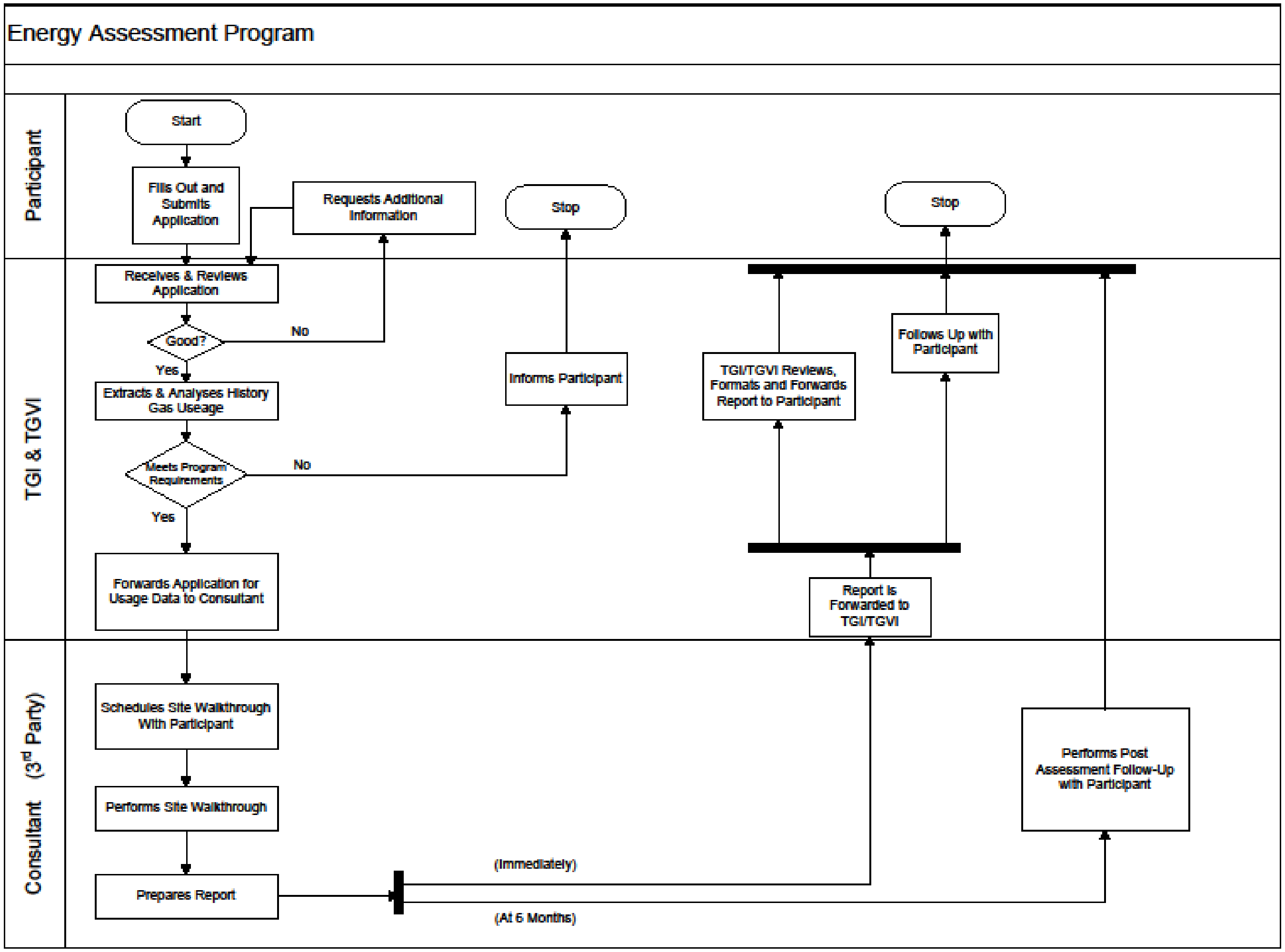
- www.terasengas.com – The Companies maintained a webpage dedicated to the program which included program information, application forms and program terms and conditions.
- Brochure: 3 panel brochure with program information and terms and conditions for hand out at tradeshows, and use by the Companies' sales and Key Accounts staff.
- Direct promotion of the program by the Companies' Key Accounts staff.

Program Administration:

Administration of the Energy Assessment Program is handled entirely in-house by the Companies' DSM Staff as of November 2009.

For new participants, the Companies' DSM staff receive applications, input data for program tracking, validate submitted information, ensure all boilers listed on applications are eligible for an incentive, prepare an incentive estimate, process and forward incentive cheques, and guide participants through the application process via on-going telephone support where / when necessary.

Additionally the Companies' DSM staff also responds to all phone or email enquires about the program from potential applicants.


Energy Assessment Program
Participant
TGI & TGVI
Consultant (3rd Party)
Start
Fills Out and Submits Application
Requests Additional Information
Stop
Stop
Receives & Reviews Application
Good?
No
Yes
Extracts & Analyses History Gas Useage
Meets Program Requirements
No
Yes
Informs Participant
TGI/TGVI Reviews, Formats and Forwards Report to Participant
Follows Up with Participant
Forwards Application for Usage Data to Consultant
Report is Forwarded to TGI/TGVI
Schedules Site Walkthrough With Participant
Performs Site Walkthrough
Prepares Report
(Immediately)
(At 6 Months)
Performs Post Assessment Follow-Up with Participant

PROGRAM: EFFICIENT COMMERCIAL WATER HEATER PROGRAM

Program Area: Commercial Energy Efficiency

Target Market: New Construction / Retrofit

Duration: TGI: April, 2010 – December 31, 2011
TGVI: April, 2010 – December 31, 2011

Incentive:

The incentive amount is calculated based on the quantity, size and type of water heating appliance installed, which must have a thermal efficiency rating great than 84 per cent for storage or hot water supply boilers, or 90 per cent for On-demand water heaters.

The structure for this program is similar to that of the Light Commercial ENERGY STAR® Boiler Program, with identical incentive amounts per input MBH for storage and boiler type water heaters. On-demand water heaters are provided with a reduced incentive due to a generally lower purchase price.

Rebates are available for multiple water heaters in a single facility and will be calculated per water heater as follows:

Storage water heaters / Hot water supply boilers
- $5 per MBH for water heaters with a thermal efficiency of 90 per cent or higher
- $3 per MBH for water heaters with a thermal efficiency of 84 per cent to 89.9 per cent

On-demand water heaters
- $2.50 per MBH for water heaters with a thermal efficiency of 90 per cent or higher

Sample calculation: 1 MBH is equal to 1,000 BTU's per hour, therefore a 199 MBH or 199,000 Btu/hr storage water heater, rated at 96 per cent thermal efficiency would be eligible for a 5 $/MBH x 199 MBH = $995 rebate.

The rebate is independent of the price of water heaters or the total cost of the water heating system. The program does not include any additional rebate or incentive for labour, vent modifications, piping changes, design calculations, or other equipment.

Program Objectives:

- Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency water heaters for domestic hot water heating.
- Increase year over year participation rates in view of maximizing gas savings.
- Educate commercial customers about the advantages of high efficiency water heaters and provide an incentive to facilitate the purchase of high efficiency technology.
- Maintain a program TRC > 1.0 and optimize the proportion of incentives over administration and marketing costs.

- Prepare the way for and support any provincial regulation requiring increased water heater efficiency.

Communications Plan:

The following initiatives will be implemented to generate consumer awareness and engagement by the trades community and manufacturers.

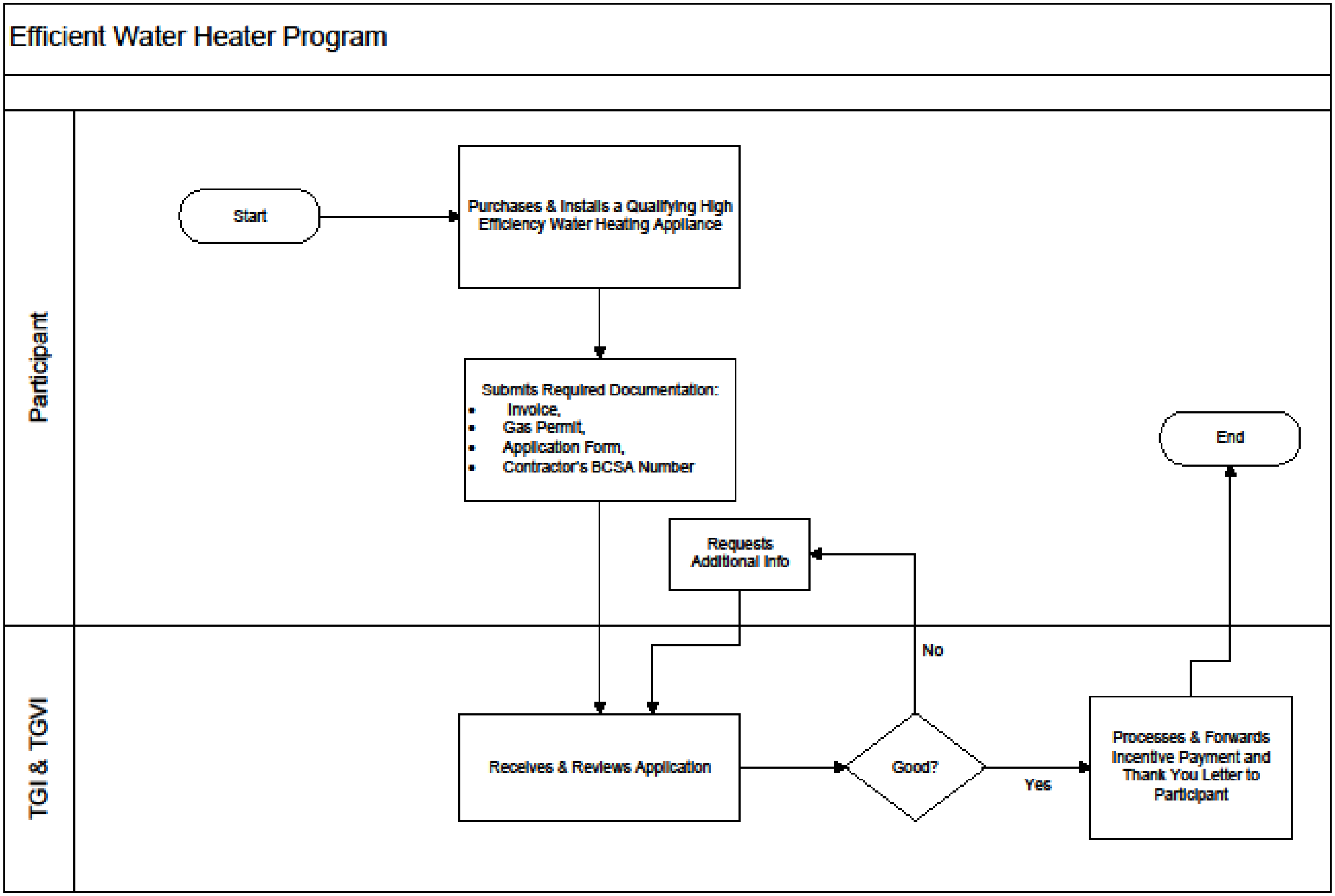
- www.terasengas.com – will include a web page with program information, application form for downloading, and program terms and conditions.
- Web tile ads will be developed for use on partner (industry association, municipalities, advocacy groups, etc) websites.
- Online directory of qualifying hot water heaters to make selection of a high efficiency water heater as simple as possible.
- Brochure: 3 panel brochure with application form/terms and conditions for hand out at tradeshows, and delivery to the Companies sales staff.
- Engagement of suppliers and manufacturer's representatives via information sessions designed to instill awareness of, and answer questions about the program.
- Lunch and learn sessions with relevant engineering firms, plumbers and gas fitters. Relevant being those who deal most often with the target customer groups.
- Speaking engagements and web page advertisements with target organizations such as:
    - British Columbia Restaurant and Food Services Association
    - British Columbia Hotel Association
    - Tourism Vancouver
    - Vancouver Hotel Association
    - Mechanical Contractor's Association of British Columbia
    - Building Operators and Managers Association
    - BC Appartment Owners and Managers Association
- Magazine Advertisement with publications such as:
    - HPAC Magazine
    - APEGBC / Innovation magazine
    - ASHRAE Newsletter
- Direct contact with target customer, as well as their attendant suppliers, engineers and O&M service providers is essential in the initial stages of the program.
- Information distributed to all customer touch points including call centres and sales and service staff

Program Administration:

Administration of the Efficient Water Heater Program will be handled entirely in-house by the Companies' EEC Staff.

For new participants, the Companies' EEC staff will receive applications, input data for program tracking, validate submitted information, ensure all water heaters listed on applications are eligible for an incentive, process and forward incentive cheques, and guide participants through the application process via on-going telephone support where / when necessary.

Additionally the Companies' EEC staff will also respond to all phone or email enquires about the program from potential applicants.


Efficient Water Heater Program
Participant
TGI & TGVI
Start
Purchases & Installs a Qualifying High Efficiency Water Heating Appliance
Submits Required Documentation:
• Invoice,
• Gas Permit,
• Application Form,
• Contractor's BCSA Number
Requests Additional Info
End
No
Receives & Reviews Application
Good?
Yes
Processes & Forwards Incentive Payment and Thank You Letter to Participant

CONSERVATION, EDUCATION, AND OUTREACH (CEO) PROGRAMS

Details of the Conservation, Education, and Outreach programs are described in this section. These programs include:

- Ethnic Outreach
- Trade Shows and Events
- Students and School Outreach
  - Destination Conservation
  - Beyond Recycling school program
  - BC Green Games
- School Assembly Presentations
- Energy Champion
- Team Terasen

PROGRAM ACTIVITY: ETHNIC OUTREACH

Program Area: Conservation, Education, and Outreach

Target Market: Punjabi and Chinese audiences, residential and small commercial customers

Duration: Begins March 2010

Program Objectives: The objective is to ensure conservation information is accessible and understood by all customers.

Methodology/Communication Plan:

The Companies are planning to conduct a qualitative and quantitative research study within the Punjabi, Cantonese, and Mandarin speaking audiences, which are the top visible minority ethnic groups in the Lower Mainland, to identify their attitudes and behaviours as they relate to conservation. Some proposed initiatives for the ethnic outreach campaign include print and online translations of the printed “Hot Tips” booklet, and event sponsorships, such as S.U.C.C.E.S.S. Foundation’s Walk with the Dragon fundraising event.

PROGRAM ACTIVITY: TRADE SHOWS AND EVENTS - HOME SHOWS, INDUSTRY TRADE SHOWS, AND OTHER SPECIAL EVENTS

Program Area: Conservation, Education, and Outreach

Target Market: residential and commercial

Duration: year round

Program Objectives:

The objective is to reach out to customers that are more inclined to home/business renovations and/or equipment upgrades and seeking information on methods to reduce energy costs.

Methodology/Communication Plan:

The Companies usually participate with a booth exhibit and/or sponsorship of a section or specific show at the event.

List of Home and Trade Show Activities for 2009

Show	Location	Residential	Commercial	Consumers Reached
BC Spring Home and Garden Show	Vancouver	x		700
CHBA Central Interior House and Home Residential Construction Trade Show	Kamloops	x		250
CHBA Central Vancouver Island Renovation Tradeshow	Nanaimo	x		250
CHBA Victoria Spring Home Show	Victoria	x		400
EPIC Sustainable Living Expo	Vancouver	x		500
GVHBA Home Renovation Seminars	Vancouver	x		300
Kelowna Spring Home Show	Kelowna	x		400
Organic Islands Festival	Victoria	x		400
Vancouver Home and Interior Design Show	Vancouver	x		800
BC Association of School Business Officials	Penticton		x	50
BC Hydro Power Smart Forum	Vancouver		x	100
British Columbia Recreation and Parks Association Symposium	Penticton		x	50
Buildex Vancouver	Vancouver		x	300
Pacific Agricultural Show	Abbotsford		x	300
Recreation Facilities Association of British Columbia Annual Conference	Oliver		x	50
Sustainabuild	Vancouver		x	50
Union of BC Municipalities Conference	Vancouver		x	200
Total Reach				5100

Proposed List of Home and Trade Show Activity for 2010

Show	Location	Residential	Commercial
CHBA Central Interior House and Home Residential Construction Trade Show	Kamloops	x	
CHBA Central Vancouver Island Renovation Tradeshow	Nanaimo	x	
CHBA Northern BC Home Show	Prince George	x	
EPIC Sustainable Living Expo	Vancouver	x	
GVHBA Home Renovation Seminars	Vancouver	x	
Kamloops Energy Fair	Kamloops	x	
Kelowna Music & Arts Festival	Kelowna	x	
Kelowna Spring Home Show	Kelowna	x	
Organic Islands Festival	Victoria	x	
Pacific National Exhibition – Prize Home	Vancouver	x	
Vancouver Home and Interior Design Show	Vancouver	x	
Victoria Home and Garden Show	Victoria	x	
BC Association of School Business Officials	Penticton		x
BC Food Service Expo	Vancouver		x
BC Hydro Power Smart Forum	Vancouver		x
British Columbia Recreation and Parks Association Symposium	Penticton		x
Buildex Vancouver	Vancouver		x
Canadian Federation of Apartments Association	Vancouver		x
Downtown Maple Ridge BIA meeting	Maple Ridge		x
Downtown Victoria BIA meeting	Victoria		x
Kamloops Central BIA meeting	Kamloops		x
Pacific Agricultural Show	Abbotsford		x
Recreation Facilities Association of British Columbia Annual Conference	Oliver		x
Strathcona BIA Sustainability 3.0 Expo	Vancouver		x
Sustainabuild	Vancouver		x
Union of BC Municipalities Conference	Whistler		x

PROGRAM ACTIVITY: STUDENTS AND SCHOOL OUTREACH - DESTINATION CONSERVATION

Program Area: Conservation, Education, and Outreach

Target Market: elementary and high schools throughout BC

Duration: September to June (school year

Program Objectives:

The goal of the program is to bring in additional school districts that would not have otherwise participated had funding not been available.

Methodology/Communication Plan:

Destination Conservation delivers education programs to students and building operators on energy, waste, and water, and assist in developing student projects for the school.

Funding:

The Companies fund the first year, and for most districts, years 2 and 3 are funded by the school district from energy savings generated from changes in facility operations prompted by the program. The exceptions to this are Okanagan Skaha and Kootenay Lake School Districts, where year 2 is funded by FortisBC, and North Vancouver School District, where years 2 and 3 are funded by the City of North Vancouver.

Destination Conservation School Sponsorship 2007 - 2009

Year	School District	Number of Sponsored Schools
2007 - 2008	Central Okanagan	7
	Okanagan Skaha	9
	Vancouver	12
2008 - 2009	Kootenay Lake	11
	Fraser Cascade	7
2009 - 2010	North Vancouver	11
	Sooke	16
	Powell River	7
	Total Schools:	**80**

For the 2010-2011 school year, Destination Conservation is currently in discussion with 5 new school districts, and 2 renewals (Kelowna and Vancouver).

PROGRAM ACTIVITY: STUDENTS AND SCHOOL OUTREACH - BEYOND RECYCLING SCHOOL PROGRAM

Program Area: Conservation, Education, and Outreach

Target Market: elementary schools in the West and East Kootenays region

Duration: September to June (school year)

Program Objectives:

The goal is to ensure conservation outreach to schools that may not have been able to participate had funding not been available.

Results:

For the 2009-2010 school year, 10 schools had signed on, reaching at least 3000 students. See table below for the list of schools.

Funding:

Additional funders of the program include Environment Canada's EcoAction Community Funding Program and FortisBC.

Schools Participating in Beyond Recycling Program 2009-2010

School	Location
Erickson Elementary School	Erickson
Canyon-Lister Elementary School	Lister
Winlaw Elementary School	Winlaw
Rosemont Elementary School	Nelson
JV Humphries School	Kaslo
Twin Rivers School	Castlegar
Glenmerry Elementary School	Trail
McKim Middle School	Kimberley
Gordon Terrace Elementary	Cranbrook
Jaffray Elementary School	Jaffray
Isabella Dicken Elementary	Fernie

PROGRAM ACTIVITY: STUDENTS AND SCHOOL OUTREACH - BC GREEN GAMES

Program Area: Conservation, Education, and Outreach

Target Market: elementary and high schools throughout BC

Duration: September 2009-June 2012

Methodology/Communication Plan:

The goal of the Companies' involvement in BC Green Games is to introduce the concept of natural gas as a resource and the need for energy conservation into the students' environmental projects. The competition allows students to learn about sustainable initiatives in other schools, learn from their peers, and build on their existing or new projects for the next year. The program is hosted by Science World who has hired a project coordinator to promote the contest to schools, organize the submissions, recruit and train the judging panel, and organize prizing.

Results:

To date, for the 2009-2010 school year, at least 94 teams have registered from 32 school districts

Funding:

The program is being co-funded with BC Hydro for 3 school years.

PROGRAM ACTIVITY: 2009 SCHOOL ASSEMBLY PRESENTATIONS

Program Area: Conservation, Education, and Outreach

Target Market: students and teachers

Duration: Spring 2009 of 2008-2009 (school year)

Program Objectives:

The goal of this initiative was to launch a program that interacted with students and brought conservation education directly into the schools. See below for a list of schools attended.

Methodology/Communication Plan:

The assembly presentation featured B.C. Lions players talking to students about environmental responsibility and then engaging with them in competitive games that focused on recycling, water, and energy conservation. After the assembly, the players visited a Grade 5 class for a more in-depth lesson.

Funding:

The program was co-funded with Livesmart BC, including both the Ministry of Education and the Ministry of the Environment, and Plutonic Power.

School Assembly Presentations, 2009 Spring

School	Location
Aubrey Elementary	Burnaby
Austin road Elementary	Prince George
Blundell Elementary	Richmond
Bowser Elementary	Bowser
Captain James Cook Elementary	Vancouver
Chalmers Elementary	Delta
Cherry Hill Elementary	Mission
Cindrich Elementary	Surrey
Clearbrook Elementary	Abbotsford
Cloverdale Catholic Elementary	Surrey
Delta Manor Elementary	Ladner
Dickens Elementary	Vancouver
Dixon Elementary (French)	Richmond
Eagle Ridge Elementary	Coquitlam
Ecole Simon Cunningham	Surrey
Erma Stephenson Elementary	Surrey
False Creek Elementary	Vancouver

School Assembly Presentations, 2009 Spring

School	Location
Foothills Elementary	Prince George
Forsythe Elementary	Surrey
Frost Road Elementary	Surrey
General Brock Elementary	Vancouver
Georgia Park Elementary	Campbell River
Glenmore Elementary	Kelowna
Glenview Elementary	Prince George
Grief Point Elementary	Powell River
Harold Bishop Elementary	Surrey
Heart Highland Elementary	Prince George
Heilings Elementary	Delta
Henry Anderson Elementary	Richmond
Hjorth Road Elementary	Surrey
Holly Elementary	Delta
Holly Elementary	Surrey
Holy Cross Elementary	Burnaby
James Thompson Elementary	Powell River
John Henderson Elementary	Vancouver
Maple Grove Elementary	Vancouver
McGirr Elementary	Nanaimo
Mundy Road Elementary	Coquitlam
Nicomekl Elementary	Langley
North Glenmore Elementary	Kelowna
Qualicum Beach Elementary	Qualicum Beach
Raymer Elementary	Kelowna
Ripple Rock Elementary	Campbell River
Riverdale Elementary	Surrey
Rutland Elementary	Kelowna
Sexsmith Elementary	Vancouver
Seymour Heights Elementary	North Vancouver
Tyee Elementary	Vancouver
W.E. Kinvig Elementary	Surrey
Walter Moberly Elementary	Vancouver

PROGRAM ACTIVITY: ENERGY CHAMPION

Program Area: Conservation, Education and Outreach

Target Market: kids, youth, and families

Duration: varies with the specific sports teams' season

Program Objectives:

The goal of the program is to educate children and youth on energy conservation behaviour in a fun and rewarding manner.

Methodology/Communication Plan:

The Energy Champion program is usually implemented in the form of a contest. An example of a contest would require kids under 12 years of age to answer the following question, "What are 3 things you can do around your home to conserve energy?" Where they would then be entered into a draw to win tickets to a game. With each sports club partnership, there are slight modifications to the program to be able to adapt to each team's delivery, but where possible, the program includes a combination of print advertising, web banner advertising, an online contest, use of social media, electronic newsletters, in-game announcements, concourse activity, and in-game activity, all to promote energy conservation.

PROGRAM ACTIVITY: TEAM TERASEN - OUTREACH TEAM AT VARIOUS COMMUNITY AND BUSINESS EVENTS

Program Area: Conservation, Education and Outreach

Target Market: residential and commercial customers

Duration: year round

Program Objectives:

The objective is to reach out to customers in their own communities (or workplace) to educate on energy conservation.

Methodology/Communication Plan:

Outreach team will usually setup a table of literature, bring an interactive game (eg. Spinning wheel) to quiz participants, and also hold a prize draw.

List of Team Terasen Events for 2009

Event	Location	Residential	Commercial	Consumers Reached
Abbotsford Air Show	Abbotsford	x		1,500
Accenture Lunch'n'Learn	Vancouver	x	x	200
BC Lions home games	Vancouver	x		900
BerryBeat Festival	Abbotsford	x		1,500
Burnaby Hospital	Burnaby	x	x	50
Burnaby Safety Event	Burnaby	x		50
Capilano University	North Vancouver	x	x	250
Chilliwack General Hospital	Chilliwack	x	x	50
Coquitlam Energy Awareness Day	Coquitlam	x	x	100
Delta Hospital	Delta	x	x	50
Dunbar Village Festival	Vancouver	x		100
Eagle Ridge Hospital	Coquitlam	x	x	50
Fort Langley BC Day	Fort Langley	x		300
Greek Day	Vancouver	x		1,500
HR MacMillan Space Centre Energy Day	Vancouver	x		100
Kelowna Music & Arts Festival	Kelowna	x		100
Langley Memorial Hospital	Langley	x	x	50
Mission Memorial Hospital	Mission	x	x	50
Moody Elementary Fun Fair	Port Moody	x		250
North Delta Lions Family Day	Delta	x		200
Ocean Park Day	Surrey	x		150
Pacific Blue Cross	Burnaby	x		100
Peach Arch Hospital	Surrey	x	x	50

Event	Location	Residential	Commercial	Consumers Reached
Pitt Meadows Day	Pitt Meadows	x		350
Play On! Vancouver	Vancouver	x		500
PricewaterhouseCoopers Eco Fair	Vancouver	x	x	60
Queens Park Care Centre	New Westminster	x	x	50
Richmond Maritime Festival	Richmond	x		700
Ridge Meadows Hospital	Maple Ridge	x	x	50
Royal Columbian Hospital	New Westminster	x	x	50
Royal Jubilee Hospital Energy Fair	Victoria	x	x	50
S.U.C.C.E.S.S. Walk with the Dragon	Vancouver	x		400
Spirit of the Sea	White Rock	x		500
Surrey Canada Day	Surrey	x		1,000
Surrey Fusion Festival	Surrey	x		1,500
Surrey Memorial Hospital	Surrey	x	x	500
Teddy Bear Picnic	Coquitlam	x		1,000
Vancouver International Airport Green Fair	Richmond	x	x	300
Vancouver International Children's Festival	Vancouver	x		20,000
Whalley Community Festival	Surrey	x		500
Strathcona BIA Sustainability 2.0 Expo	Vancouver		x	50
West End BIA Sustainability Fair	Vancouver		x	50
Total Reach				35,210

Proposed List of Team Terasen Events for 2010

Event	Location	Residential	Commercial
Abbotsford Air Show	Abbotsford	x	
BC Hockey League games	various	x	
BC Lions street party	Vancouver	x	
BerryBeat Festival	Abbotsford	x	
Greek Day	Vancouver	x	
North Delta Lions Family Day	Delta	x	
Pacific National Exhibition Fair	Vancouver	x	
Pitt Meadows Day	Pitt Meadows	x	
Play On! Kelowna	Kelowna	x	
Play On! Vancouver	Vancouver	x	
Port Moody Fingerling Festival	Port Moody	x	
Richmond Maritime Festival	Richmond	x	
S.U.C.C.E.S.S. Walk with the Dragon	Vancouver	x	
Spirit of the Sea	White Rock	x	
Strathcona BIA Sustainability 3.0 Expo	Vancouver		x
Teddy Bear Picnic	Coquitlam	x	
Vancouver Giants	Langley/Vancouver	x	
Vancouver International Children's Festival	Vancouver	x	
Whalley Community Festival	Surrey	x	

ENABLING ACTIVITIES

Details of the enabling activities programs are described in this section. These activities include:

- Research and Evaluation
  - Residential End Use Study (REUS)
  - Sustainability and Social Responsibility Attitudes Study Report
  - Residential Retrofit Market Evaluation for Terasen Gas
  - ENERGY STAR® Heating System Upgrade Evaluation
  - Efficient Boiler Program Evaluation
  - Okanagan Spray Saver Pilot Program Evaluation
  - Conservation Education and Outreach 2010 Evaluation

- Efficiency Partners Program
  - Contractor Program (2009)
  - New Contractor Program (2010)

- Pilot Programs (2009)
  - Okanagan Spray Saver Pilot Program
  - Furnace Servicing Pilot – "Give Your Furnace Some TLC" Campaign
- Pilot Programs (2010)
  - Behaviour Change - Vancouver Coastal Health Authority and Providence Health Care staff engagement
  - Behaviour Change - Destination Conservation for Public Buildings Pilot Program
  - Domestic Hot Water Tier Three Technologies pilot
  - EnerGuide 80 Program

RESEARCH & EVALUATION: RESIDENTIAL END USE STUDY (REUS)

Program Area: Residential Energy Efficiency Programs

Methodology:

Due to complexity of the REUS, the final results were completed and compiled towards the end of 2009. Prior to the 2008 REUS, two REUS studies were conducted by TGI (formally BC Gas), one in 1993 and a second one in 2002. Neither of these prior studies included TGVI. The 2008 REUS study sought to understand what factors impacted residential gas usage across TGI *and* TGVI. These included appliance efficiency, changes in housing construction and customer behaviours and attitudes. The study was jointly funded by several departments within the Companies, including the EEC group. The overall cost of the project was $213,000 which included EEC's contribution of $20,000.

Planning for the study was started in spring 2008 with an RFP issued in summer 2008. Sampson Research was selected to conduct the research in conjunction with Habart & Associates Consulting Inc., NRG Research Group, InterVISTAS Consulting Inc. and Innes Hood Consulting Inc. The fieldwork was undertaken in December 2008, and it took about twelve months to complete the research due to the complexity of the project. The study included TGI and TGVI residential customers from each of the following five regions: Lower Mainland, Interior, Vancouver Island/Sunshine Coast, Whistler and Fort Nelson. The fieldwork consisted of a survey questionnaire which was mailed to respondents; however, they had the option of completing and mailing the paper survey or completing online. Over 2,200 surveys were completed. The analysis was completed by May 2009 and the final report was completed by November 2009. In addition a Conditional Demand Analysis and a Segmentation Analysis were completed to complement the REUS. The highlights of this extensive study are outlined in the below.

Findings:

Trend Analysis

Declines in weather normalized use rates (i.e., gas consumption per household) have been experienced in four of the five Terasen Gas Inc regions between 1999 and 2008. Overall, the Companies' use rates are down 15.5 per cent since 2002 and 20.7 per cent since 1999. Whistler was the only region experiencing an increase in its residential use rate since 2002 (+6.4 per cent).

Declines in natural gas use rates are primarily attributed to the following factors and trends:

- Construction of smaller, less energy-intensive multifamily dwellings including townhouses, and apartments.
- Improvements in the thermal envelope of homes (improved insulation, energy efficient windows, etc.).

- Improvements in the efficiency of gas end uses including furnaces, water heaters, and fireplaces.
- Improvements in the efficiency of hot water-using appliances, including front loading clothes washers, and dishwashers.
- The long-term decline in the average number of people per-household.
- Reduced hot water demand stemming from the aging of the population and proportionately fewer households with young families.
- Increases in the price of natural gas. The inflation-adjusted variable rate portion of natural gas prices in the Lower Mainland region, for example, increased by 10 per cent between January 2002 and December 2002, and 78 per cent since January 1999.

Trends countering the decline in use rates include:

- Increased space heating requirements of newer single family detached homes due to increased interior volumes (increased ceiling height and increased floor area), i.e. takes more energy to heat houses with high ceilings (10 or 12 feet) as opposed to regular height of 9 feet)

Building Envelope & Renovations

- Eighty-three percent (83 per cent) of respondents to the 2008 REUS live in single family detached (SFD) dwellings, 13 per cent in duplexes or townhouses, one per cent in apartments or condominiums, and 3 per cent in mobile homes or other dwelling type.
- Individually metered suites within a multi-storey building, also described as vertical sub-divisions (VSDs), are home to higher proportion of younger residents (under the age of 44) compared to SFDs and other multifamily dwellings (MFDs).
- The average length of residence (years living in the same premise) is increasing, presently 15 years, up from 10 years in 1993. The frequency of changes in residence decreases as people age.
- Average size (floor space) varies by building type and dwelling vintage. SFDs averaged 2,263 ft2, compared to 1,672 ft2 for MFDs, and 1,291 ft2 for VSDs. SFDs built after 1985 tend to be larger (up to 24 per cent larger), on average, that those built earlier.
- The incidence of partially or completely finished basements is increasing, up from 62 per cent in 1993 to 68 per cent in 2008.
- Nearly three quarters (74 per cent) of basements and crawlspaces are heated during the winter season.
- Homes built after 1985 are increasingly likely to have nine or ten foot ceilings, compared to the traditional eight foot ceiling of homes of older homes. VSDs are more likely than SFDs and MFDs to have nine or ten foot ceilings (average of 60 per cent versus 23 per cent and 35 per cent respectively). The majority (81 per cent) of VSDs were built since 1995.
- Consistent with trends in housing construction and changes in building codes, newer homes are more likely to have average or above average insulation, high efficiency windows, and insulated outside doors.

Renovation Activities – Past and Planned

- The top three renovations undertaken in the last five years include purchasing energy efficient appliances (37 per cent of customers), installing weather stripping or caulking (21 per cent), and installing a low flow showerhead (19 per cent). These are also the top three activities expected to be occur during the next two years. A comparison of stated intentions from the 2002 REUS with renovations undertaken during the past five years by 2008 REUS respondents suggests that, with a few exceptions, stated intentions are a good predictor of future actions.

- Eleven percent (11 per cent) of customers made changes involving fireplaces or heating stoves during the last five years, and 8 per cent plan to undertake similar renovations in the next two years.

Space Heating

- Nine-in-every-ten customers use natural gas as their primary space heating fuel; a proportion that has remained stable since 1993.
- Fifty-six percent (56 per cent) of customers use a supplementary fuel to heat their home. Electricity is the predominant supplementary space heating fuel, used by 67per cent of these customers. Wood is the second most common supplementary space heating fuel (14 per cent).
- Compared to 2002, the use of electricity as a supplementary space heating fuel has increased from 58 per cent to 73 per cent of TGI households that use supplementary space heating fuel.
- Three percent (3 per cent) of customers switched their main space heating fuel in the last five years, with a net shift being from natural gas to electricity. This shift is most evident in the Lower Mainland, Interior and TGVI regions.
- Regardless of main heating method, gas fireplaces are the most commonly used secondary method of heating among customers (29 per cent of TG customers). Wired-in and portable electric heaters are the second and third most common methods (11 per cent and 10 per cent respectively).
- VSDs are significantly more likely than SFDs or MFDs to use a gas fireplace as either the main or secondary heating method.
- Interior and Fort Nelson customers are significantly more likely than households in other regions to use a wood stove as their secondary heating method.
- On average, 22 per cent of customers have installed a new gas furnace or boiler in the last five years, primarily because of equipment failure (anticipated or actual). High efficiency furnaces were chosen by 40 per cent of those installing a furnace.
- Seventy-three percent (73 per cent) of customers with a standard efficiency furnace leave their furnace’s pilot light on for 12 months of the year.

Fireplaces and Heating Stoves

- Eighty-five percent (85 per cent) of customers have at least one fireplace and/or free standing heating stove.
- The top three most popular fireplace types are heater type gas fireplaces (50 per cent of customers), wood burning fireplaces (28 per cent), and decorative gas fireplaces (22 per cent).
- Penetration of fireplaces and heating stoves is highest in TGW (98 per cent of customers) and TGVI (90 per cent), and lowest in the Fort Nelson region (47 per cent).
- Twenty-eight percent (28 per cent) of respondents with a gas fireplace that uses a pilot light, never turn off the pilot light.
- Fireplace operating hours are highest in the Fort Nelson and TGVI regions (766 and 702 hours per year, respectively), and lowest in the Lower Mainland region (393 hours). Average wintertime usage by region is correlated with the regional climate (e.g., number of heating degree days).
- Average annual use of fireplaces and heating stoves is significantly higher for VSDs (697 hours per year) than SFDs (459 hours) and MFDs (387 hours). This is consistent with the greater tendency of customers living in VSDs to use their fireplace as either a primary or secondary space heating method.

Water Heating

- The penetration rate of gas-fired hot water tanks among Companies' customers is 89 per cent, up from 85 per cent in 2002.
- Whistler households are significantly more likely than any other region to have two or more hot water heaters. This is consistent with the high incidence of secondary suites in the resort community.
- Storage-type hot water tanks (any fuel) continue to make up the vast majority of hot water heaters. One percent (1 per cent) of customers have condensing style hot water heaters and 3 per cent have an instantaneous hot water heater.
- Thirty-eight percent (38 per cent) of customers have replaced their hot water heater during the last five years. This is on par with the findings from the 2002 REUS.
- The penetration of hot water heater blankets is 6 per cent of households, down from 15 per cent in 2002. Improvements in the tank wall insulation of new hot water heaters has reduced the cost-effectiveness of hot water heater blankets.
- Eighty-one percent (81per cent) of customers use either piped gas or propane for both their main space heating fuel and their water heating fuel.
- Only one percent (1per cent) of respondents use solar energy to pre-warm or supplement water heating.

Appliances

- The penetration of gas ranges has increased from 9 per cent of TGI households in 1993, to 17per cent of households in 2008.
- Front loading clothes washers have increased their penetration from 9 per cent of TGI households in 2002 to 27 per cent in 2008, largely at the expense of the lesser-efficient top-loading models.
- The proportion of home appliances rated ENERGY STAR® varies from a low of 2 per cent for air conditioners to a high of 53 per cent for refrigerators.

Pools and Hot Tubs

- Six percent (6 per cent) of households have a swimming pool that is for their exclusive use only (i.e., not shared with other residences, as is the case in multifamily complexes).
- Forty-three percent (43 per cent) of swimming pools are heated with natural gas. The next most commonly used fuels are solar (15 per cent) and electricity (5 per cent). Thirty-six percent (36 per cent) of pools are not heated.
- Thirteen percent (13 per cent) of households have an exclusive use only hot tub.
- Electricity is the predominant fuel used to heat hot tubs (83 per cent of all households with an exclusive use hot tub). Only 15 per cent of households with a hot tub use piped gas or propane to heat the water.
- Ninety-five percent (95 per cent) of hot tub owners use a hot tub cover. Sixty-nine percent (69 per cent) of pool owners use a pool cover.

Behaviours

- Fifty-five percent (55 per cent) of Companies' customers use at least one programmable thermostat to control temperature in their home.
- Eighty-three percent (83 per cent) of customers with thermostats (programmable or otherwise) always or usually set back the temperature at night, and 70 per cent of them so during the day when no one is at home.
- Customers in electrically heated homes are more likely than those in gas heated homes to keep unoccupied parts of the house cooler than the rest of the home (77 per cent versus 64 per cent, respectively). Customers living in VSDs have a lower share of their rooms that are always heated than do those living in SFDs (52 per cent versus 79 per cent respectively).
- Forty-one percent (41per cent) of respondents said their home is either always or somewhat drafty. Efforts at draft proofing were unsuccessful for 26 per cent of respondents.
- The use of window coverings (storm windows or plastic sheeting) is highest in the Fort Nelson region, and is more common among rental properties and homes with single pane windows.

- The number of showers, laundry loads, dishwashing loads, and baths decrease as the number of people in the home decrease. A household that decreases in size from four members to two (e.g., the typical situation when grown-up children leave home) will see, on average, a 36 per cent decline in the number of dishwasher loads, a 43 per cent decline in the number of laundry loads, a 30 per cent decline in the number of baths, and a 53 per cent drop in the number of showers.
- Thirty percent (30 per cent) of respondents, on average, turn down, turn off, or use the vacation setting on their hot water heater when away from home for more than a few days.
- On average, 58 per cent of laundry is washed using cold water.

Programs and Services

- Eleven percent (11 per cent) of respondents have participated in a program to reduce energy use in the last five years, with the program sponsored by either Terasen, a government agency, or some other organization or company.
- Interest was highest for a furnace tune-up program, home energy audits, and a do-it-yourself online energy audit.
- Eighty-five percent (85 per cent) of customers claimed they were at least somewhat knowledgeable about ways to save energy. Only 13 per cent categorized themselves as very knowledgeable.
- Seventy-eight percent (78 per cent) of respondents to the 2008 REUS agreed that natural gas is a clean and efficient energy source, unchanged from the 2002 REUS.
- Seventy-four percent (74 per cent) agreed with the statement “natural gas is a safe energy source”. Regional results did not differ significantly with the exception of Interior residents who were somewhat more in agreement with the statement than residents in the other regions.

Conditional Demand Analysis

A conditional demand analysis (“CDA”) was conducted using data from the 2008 REUS, billing records, and regional weather stations to estimate unit energy consumption (“UEC”) estimates for each of the major gas end uses including main and secondary space heating, water heaters, fireplaces, cook tops, pools, hot tubs, and barbeques. Estimates were generated for the five TG regions and TGI. Highlights include:

- Primary and secondary space heating are the two largest gas end uses, consuming 58 GJ/year and 23 GJ/year, respectively.
- Other major gas end uses are water heating (20 GJ/year), decorative fireplaces (21 GJ/year), and heater type fireplaces (17 GJ/year).
- Consistent with their tendency towards smaller household sizes (i.e., number of people per home), UECs for gas water heating for VSDs and MFDs are lower than SFDs.

RESEARCH & EVALUATION: SUSTAINABILITY AND SOCIAL RESPONSIBILITY ATTITUDES STUDY REPORT

Program Area: Residential Energy Efficiency Programs

Methodology:

Produced by Conscientious Innovation ("CI"), a Vancouver-based market research firm, the Sustainability and Social Responsibility Attitudes Study ("SHIFT") report is a market research tool comprised of qualitative and quantitative research, cultural reporting and trend analysis. Since Companies' financial commitment to the report was made before the research went into the field, the Companies were offered an opportunity to insert a number of questions related to media brands, lifestyle activities and consumption behavior.

The methodology of the SHIFT report includes both qualitative and quantitative data. The former is based on the results of over 32 focus groups conducted in Canada and the US as well as secondary market research analysis. The latter is based on 5,000 responses from the general North American population conducted through an online panel. Terasen Gas provided input specific to home energy and energy efficiency in mid-2009 during the design stage of the study. The analysis was completed by December 2009 and the final report was completed by January 2010.

Findings:

The results of the SHIFT report home energy consumer study is a resource for Terasen Gas staff to assist them in designing and implementing EEC programs. It summarizes detailed findings on consumers who are making sustainable choices related to home energy. The key findings of the report are:

- 60 per cent of North Americans say they have already made sustainable and socially responsible choices related to Home Energy
- 69 per cent of Canadians say they have already made sustainable and socially responsible choices related to Home Energy
- 64 per cent of Home owners versus 56 per cent of Home Renters say they have made sustainable and socially responsible choices related to Home Energy
- Food, Home Cleaning and Gardening/Yard Work are the top three other areas they say they have made sustainable lifestyle choices & purchase decisions
- Lighting and Home Heating are the top two areas they say they have made sustainable lifestyle choices & purchase decisions related to Home Energy
- 65 per cent are concerned about the health and environmental toxins in products today
- 61per cent rate Global Warming as important
- 33 per cent rate Organic Products as important

The top 5 sustainability issues (in terms of importance) are:

- Feeling connected to my friends, family & community (90 per cent)
- Balanced life (90 per cent)
- Being paid a living wage (88 per cent)
- How employees are treated at companies (86 per cent)
- Nurtured personal relationships versus material possessions (83 per cent)

RESEARCH & EVALUATION: RESIDENTIAL RETROFIT MARKET EVALUATION FOR TERASEN GAS

Program Area: Residential Energy Efficiency Programs

Methodology:

The LiveSmart BC Residential Retrofit Incentive Initiative launched in May 2008, by the Provincial government, provided incentives to reward residential retrofits that saved energy and reduced GHGs. As part of the Energy Efficient Buildings Strategy, the goal was to create a one-stop shop to provide homeowners with coordinated, easy access to utility, provincial, and federal incentives Data-gathering for the LiveSmart partnership was done through NRCan ecoENERGY Home Renovation program. The first phase of the LiveSmart BC Residential Retrofit Incentive Initiative was initially set for a three-year period, however it was fully subscribed with over 40,000 participants within the first 15 months. With the provincial funding fully utilized, the first phase of LiveSmart BC expired on August 16, 2009.

With the end of this first phase, the utility partners in LiveSmart BC (the Companies, BC Hydro and Fortis BC) are actively working on rolling out a new version of a collaborative residential retrofit incentive program. Utilities-driven DSM programs are required to adhere to strict cost-benefit analysis that is focused on the overall societal benefits and have an established outreach and cost-effective channels for their target customers. Government-driven programs can contribute by supporting new technologies and providing subsidies for measures such as home energy audit assessments where there is zero savings.

In November 2009, Terasen commissioned Angus Reid Strategies to evaluate awareness levels among members of the general population regarding energy efficiency programs, rebates and incentives. The study was designed to provide insight into the various factors that motivate homeowners to participate in incentive programs, as well as to determine awareness of existing programs and brands.

The fieldwork was undertaken in December 2009; the cost of the study ($17,800) was covered by The Companies[3]. The sample size consists of over 840 of BC homeowners who are responsible for directly paying their utility bills. The analysis was completed in early January 2010, and the final report was delivered in late January 2010.

Findings:

- The type of energy used to heat the home has a significant impact on the monthly energy bill. Those using natural gas as their primary heating source report paying a higher monthly bill. Those with higher monthly bills are more likely to participate in energy efficiency incentive programs.

[3] Note that the final report was delivered in January 2010, and the full payment was made then; therefore, the cost of the study is not reflected in the 2009 budget but rather in 2010.

- BC homeowners say it is important to reduce their energy use, the majority because it will save money. Of the one-third of homeowners have participated in an energy efficiency incentive program, the most common reasons are to save money, take advantage of incentives and to improve the comfort of their home.

- Eight brands were evaluated for awareness and participation. As to be expected due to budget levels and time-to-market, BC Hydro's Power Smart program has the highest awareness and participation among homeowners, followed by ENERGY STAR®. LiveSmart BC is in the middle of the pack with three-in-five homeowners aware of the program but only one-in-five participating in the program.

RESEARCH & EVALUATION: 2005-2007 ENERGY STAR® HEATING SYSTEM UPGRADE EVALUATION

Program Area: Residential Energy Efficiency Programs

Methodology:

The ENERGY STAR® Heating System Upgrade Evaluation was commissioned in the summer of 2007; the first phase was completed in early 2008. The second phase was completed in late 2008 with final results delivered in early 2009. The ENERGY STAR® Heating System Upgrade Evaluation was performed by Sampson Research, a BC-based market research firm, with Habart serving as advisors to the study.

The Program offered residential customers a financial incentive of $250 towards the purchase of an ENERGY STAR® qualified High Efficiency Natural Gas Furnace (“HEF”) or boiler. There was an additional incentive when the qualifying furnace was equipped with a Variable Speed Motor (“VSM”). The primary objectives of the program were to reduce energy consumption, peak demand, and GHGs for residential customers by increasing the energy efficiency of their home heating systems. A total of 8,652 residential customers participated in the program for the timeframe of September 2005 to March 2007. Rebates and incentives totalled $2.73 million. Funding for the incentives was provided by Terasen, with co-funding from MEMPR, BC Hydro, FortisBC, and NRCan.

The objectives for the first phase of the study were:

- Assessing factors influencing program participation, the effectiveness of program marketing / advertising, free ridership, reasons for non-participation, and overall customer and trade ally satisfaction with the program.
- Assessing program impact on sales of qualifying HEF’s, and VSM, for both participating and non-participating customers
- Documenting and assessing program impact on furnace and secondary heating operating behaviours that affect energy use, with particular emphasis on hours of operation
- Determining the status of market transformation for HEF’s, and furnaces with variable speed drive blower motors in the British Columbia market
- Developing preliminary estimates of program impact on natural gas sales and carbon dioxide emissions.

The completed report of phase one of this study was filed in the response to EEC Application BCUC IR 1.71.2.1, filed on July 11, 2008.

The primary objective of the second phase of the evaluation was to update estimates of program energy and demand savings using a comparison of weather normalized billing histories for participants, and a comparative sample of non-participants (billing analysis). The estimate of gross program savings derived from the billing analysis would be adjusted for free riders and program spillover to determine net program energy and peak demand savings.

Findings:

First Phase

- 57 per cent of participants in the Terasen program credited the program with influencing their decision to purchase a high efficiency furnace, meaning that 43 per cent of participants were free-riders and would have selected a high efficiency furnace without the incentive.

Second Phase (Including updated first phase results):

- Based on net 9.6 GJ per annum savings per high efficiency furnace, the program generated 78.8 terajoules ("TJ") in annual savings for the first 2.3 years and 47.4 TJ of annual savings in subsequent years.

- The gross energy savings per-participant from retrofitting to a high efficiency furnace were estimated at 9.6 GJ per year—this number is lower than the Phase I engineering estimate of 13.4 GJ per year.
  - One possible explanation for the decrease in estimated savings for retrofitting with a high efficiency furnace is that non-participants tended to replace furnaces that had a lower AFUE rating relative to that of participants.

- Based on the evaluation results, Terasen's 2005-07 Heating System Upgrade Program will reduce Carbon Dioxide ("CO2") emissions by 3.940 kilotonnes annually for the first 2.3 years and 2.370 kilotonnes annually for subsequent years.
  - CO2 reduction estimates are based on Terasen's emissions reduction factor of 50 tonnes carbon dioxide per TJ of energy saved.

The Table below summarizes the energy savings attributable to Terasen's 2005-07 residential Heating System Upgrade Program based upon billing analysis results, a net-to-gross ratio of 0.57 and a spillover of 2.3 years.

Energy Savings Estimates – September 2005-March 2007

Impact Component	Unit Savings (GJ)	Gross Participants	Gross Savings (TG)	Net to Gross Ratio	Net Savings (TJ)
Direct	9.6	8,652	83.1	0.57	47.4
Spillover	12.1	2,596	31.4	-	31.4
Annual - first 2.3 years	-	-	-	-	78.8
Annual - subsequent years	-	-	-	-	47.4

RESEARCH & EVALUATION: EFFICIENT BOILER PROGRAM EVALUATION

Program Area: Commercial Energy Efficiency Programs

Methodology:

TGI and TGVI will select a sample of approximately 30 previous participants who have successfully installed high efficiency boilers in order to perform a billing analysis. TGI and TGVI will compare the participating buildings' weather normalized, pre-installation gas consumption, to its weather normalized post installation gas consumption in order assess the impact of the boiler installation. The difference between the two, absent the presence of any other measure significantly impacting gas consumption, will be attributable to the boilers. Other measures which may have impacted gas consumption will be identified via an interview with the building owner/participant.

The sample group selected for the billing analysis will be from those participants who have successfully completed their boiler installation prior to 2009. Thus the new boilers will have operated for at least one (1) full heating season prior to the analysis of the consumption data.

Note that while the billing analysis will necessarily focus on participants with a previous billing history (ie retrofits as opposed to new construction) the findings will be applicable to both retrofit and new construction participants for the purposes of tracking energy savings. This is because the end result of the analysis will be a percentage reduction factor to energy consumption attributable to high efficiency versus standard efficiency boilers. Thus the reduction factor applies to new construction participants since the baseline case against which their high efficiency boiler(s) derives energy savings is a standard efficiency boiler.

RESEARCH & EVALUATION: EVALUATION OF OKANAGAN SPRAY N' SAVE PILOT PROGRAM

Program Area: Commercial Energy Efficiency Programs

Methodology:

The following methodology is proposed for the second round of the Okanagan Spray N' Save Pilot Program Evaluation

Further to the initial arithmetic analysis, a number of participants will be included for metering of their actual hot water consumption in order to empirically confirm the gas savings associated with the spray valves. First a sample consisting of approximately 30 willing participants will be identified. TGI will then have water meters will be installed by a licensed plumber as follows:

1. Flow meters for the hot water line serving the spray valve.
2. Temperature meters on the inlet and outlet water pipes of the hot water heaters.
3. A data logger will be installed to record the water flow and temperature information for the length of the metering period.

Usage data will be collected from the data logger at 2 week intervals for a period of 1 month. Subsequently the new low flow spray valve will be removed and the old, standard flow rate spray valve will be reinstalled. Once again usage data will be collected from the data logger at 2 week intervals for a period of 1 month. After completion of the data collection the new, low flow spray valve will be reinstalled. The collected data will be reviewed to establish actual energy savings.

Subsequent to all data collection/processing the results will be compared and used to establish a reasonable and prudent estimate of the gas savings attributable to the program.

RESEARCH & EVALUATION: CONSERVATION EDUCATION AND OUTREACH 2010 EVALUATION

Program Area: Conservation Education and Outreach Programs

The benefits of CEO initiatives are also not currently translated directly into energy savings; however, the costs are included in the Portfolio Level analysis, and the overall portfolio TRC test results still have to be greater than 1.0. Historically, CEO initiatives were limited to print and online publications, trade shows, and limited school programs.

Advertising Tracking

Advertising tracking, as discussed in the Companies' response to EEC Application's BCUC IR 1.47.1, can be used to investigate the effectiveness of specific commercials or ad campaigns in terms of the recall of specific messages, changes in people's perceptions, and behavioural changes in the target audience. Tracking research generally consists of telephone interviews with homeowners (gas and non-gas customers). This would be conducted with a representative sample of target-audience consumers from the TGI and TGVI service areas. It can investigate the effectiveness of specific commercials or campaigns in terms of the recall of specific messages, changes in people's perceptions, and behavioural changes in the target audience. It answers questions like the following:

- What messages and ideas from the advertising do consumers remember?
- Do the remembered messages correspond to the advertising messages that the advertising was intended to communicate?
- Did the messages and ideas translate into action?

Process Evaluations

Process evaluations typically measure the effectiveness of the program by assessing how well the program met a set of goals or metrics defined by the program administrators. This method has been used by other utilities and American state agencies, such as Southern California Edison, and Pacific Gas & Electric.

Examples of goals/metrics for educational and communication programs include:

- What messages and ideas from the advertising do consumers remember?
- Do the remembered messages correspond to the advertising messages that the advertising was intended to communicate?
- Did the messages and ideas translate into action?

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Examples of goals/metrics for educational and communication programs include:

- Increase awareness of the relationship between energy and the environment among students
- Deliver at least two special events annually during which the public is exposed to specific key messages and provide with information and materials

Examples of techniques used to assess whether goals/metrics are met include:

- In-depth interviews with program staff
- Survey of program participants, and qualitative analysis of responses
- Focus groups of program participants

Web Analytics

Web analytics is the measurement of the behaviour of visitors to a website. Simply put, web analytics is the process of understanding the Companies' online presence so that it can be optimized. The Companies work with Omniture SiteCatalyst, a remotely hosted, subscription-based solution for real-time web site reporting and analysis. Codes are placed on the Companies' webpages that execute when the page loads. As the page loads and the code on the page executes, it sends a request to the SiteCatalyst server for a web beacon, a two-by-two transparent pixel image. Along with this image request, the code collects and sends additional information to Omniture data centres. The data centres then populate a report with the collected data, which can be accessed by the Companies' web team, to allow them analyze the web activity related to a specific CEO initiative.

EFFICIENCY PARTNERS PROGRAM: CONTRACTOR PROGRAM (2009)

Program Area(s): Commercial and Residential Energy Efficiency Programs

Target Market: Majority Residential & Minority Commercial

Duration: Summer 2007 through April 30th 2010

Objectives:

- Provide customers with accurate energy efficiency cost versus benefit options through industry partner groups.
- Encourage contractors to educate and nurture a change in customers' daily energy use habits by providing EEC program information, general efficiency advice and supporting collateral publications such as Hot Tips.
- Through the partner groups, promote EEC programs utilizing energy efficient appliances and services such as ENERGY STAR® and Enerchoice.
- Promote the best use of Provincial energy resources.
- Help to provide contractors with education on new energy efficient technologies
- Achieve a higher level of customer confidence in the quality of services rendered by contractors (safe and fairly priced).
- Improve the overall quality of installers through cooperative BC Safety Authority and supplier workshops educating the methods to properly install and maintain more complex energy systems.
- Improve communication between Terasen's EEC department and the Energy Efficiency Industry stakeholder groups through quarterly information news letters.

Background:

In 2007, TGVI's Qualified Dealer Program ("QDP") was reintroduced in the TGVI service territory, with an emphasis on further upgrading the quality of the participating gas contractors, in order to ensure that customers had access to highly qualified gas contractors. Contractors were required to re-register for the QDP which now had more stringent guidelines as follows:

- Better Business Bureau reference
- BC Safety Authority Registration
- Business supplier referral
- Customer referral
- Business license
- Worksafe BC coverage
- Two million dollar minimum liability insurance
- Business credit check

Since the re-launch of the program in 2007, and until the increased EEC funding was approved in April of 2009, limited resources were devoted to the QDP and essentially no incentive program offers for the TGVI market area were provided. There are currently only about 75 QDs registered in the TGVI area out of a total market of approximately 350 gas contractors located in the TGVI service area.

The marketplace has changed significantly since the QDP was first launched. Since the QDP was focused on TGVI, customers were looking primarily for a gas contractor to convert them to natural gas and service their natural gas products. Today's energy consumer is looking for a wide range of services that include reliable information sources and manufacturers, installers and service contractors who will provide energy efficiency recommendations for their entire house. This will require expanding the scope of the QDP to eventually include additional groups such as A and C ticket contractors. The QDP will also need to include new Energy Efficiency service groups such as EcoEnergy Home Assessment auditors and draft-proofers. The large number of gas contractors located in the Lower Mainland, the Interior, and Vancouver Island represent an excellent opportunity for Terasen to promote a "whole-house" energy concept to customers. A whole-house system approach considers the interaction between the building site, regional climate, energy consumption habits, appliance efficiency and other elements or components in the home. Reduction of appliance energy utilization alone will not achieve the total provincial BC Energy Plan targets. The B-ticket gas contractors are one of the largest industry groups that influence end use customers. Domestic/commercial BC Safety Authority licensed B-ticket gasfitters install, test, maintain and repair propane and/or natural gas lines, appliances, equipment and accessories in residential and commercial premises up to 75,000 BTU. Industrial A-Ticket gasfitters perform the same tasks as B plus unlimited BTU range in industrial settings. They may work in new construction, or be installing systems in existing buildings that are being upgraded. C-tickets are limited to residential gas appliance servicing only. The company's overall objective for this market sector is to expand and rebrand the existing TGVI Qualified Dealer Program (B-ticket contractors) in breadth and scope and to open the new contractor program to include the Lower Mainland and the Interior.

The new contractor program will also eventually include efficiency service groups that have been previously excluded from the QDP. The program should be structured to be able to eventually include the following Efficiency Partners over time:

- appliance installation contractor (A&B ticket)
- gas appliance service groups (C ticket)
- suppliers & distributors
- big box retailers
- residential and commercial energy auditors
- weatherization services (draft proofers)
- support groups, i.e. regulators, colleges
- associations

The rationale behind this expansion is that the current QDP has limited capabilities with the majority of the participating TGVI contractors being small, "mom and pop" types of businesses. With an expansion to the Lower Mainland and Interior service areas, there is a concentration of much larger companies that will involve working with supplier and distribution groups. This will be especially true with big box stores. With the inclusion of a comprehensive group of service providers in a Terasen contractor program, customers will have access to a reliable network of energy efficient service providers with the ability to assist them with a wider range of efficiency services.

New Contractor Program Development Milestones:

In the third quarter of 2009 the efficiency partners program was established with a focus on evaluating and expanding the existing contractor program. The following is a list of the 2009 contractor program development milestones:

- Internal QDP program review of existing procedures and participation (complete)
- Connect with industry stakeholders for feedback and opportunities for collaboration (complete)
    i. Representatives of existing Qualified dealers on TGVI
    ii. Contractor supplier groups
    iii. Manufacturers and Distributors
    iv. Contractor Associations
    v. Trades Training Groups
    vi. BC Safety Authority
    vii. Thermal Environmental Comfort Association (TECA)
    viii. Mechanical Contractors Association (MCA)
- Conduct TGVI gas contractor survey (complete)
- Facilitate three contractor focus groups on Vancouver Island (complete)
- Initiate the rebranding of the program (ongoing)

Feedback from all groups surveyed was very positive. All groups are looking forward to participating in the new Efficiency Partner Contractor program and recognize the need for Companies' participation to achieve transformation of the energy efficient equipment marketplace. A summary of feedback specifically from the Vancouver Island Contractor Focus Groups can be found below:

- The face of the contractor is changing and many are moving away from mail and fax machines to e-mail communication.
- The concept of quarterly newsletters and cooperative workshops with supplier groups was well received.
- Emphasis was placed on the timing of introducing programs with the fall and spring being the busy periods for contractors. There were many requests to have advance notice of new programs and information on new emerging efficiency technologies.
- 75 per cent of water heater replacements take place in emergency situations, after the appliance fails and the rest are planed replacement units. Ninety five per cent responded positively to promoting ENERGY STAR® furnaces. As well, most agreed that customers were asking about high efficiency.
- Keep programs simple avoiding extra paperwork for Contractors feel the utility needs more face to face connection with customers. The EEC department should attend smaller home shows alongside local gas contractors and suppliers.

The findings from the Vancouver Island Contractor Focus Group informed the Companies that customers are asking about energy efficiency and contractors can only work with the information they have from specific suppliers. The focus groups were very well attended and contractors were positive and looking forward to participating in the new program. Focus Groups will be held in the Lower Mainland and Interior in 2010. Results from the TGVI focus groups will allow for a possible link up with BC Safety Authority B-149 Training sessions.

Co-Op Advertising:

To help promote energy efficient natural gas products and services, a Co-op Advertising program is available for existing Qualified Dealers on TGVI, for those that choose to participate. Co-op Advertising dollars are provided for the following media:

- Print (**Note: Print ads in the Yellow Pages of a telephone directory are not eligible for co-op advertising.)*
- Radio
- Television
- Direct mail (i.e. flyers)
- Home show displays *(promoting natural gas fired equipment only)*

In order to qualify for co-op advertising dollars, the advertisement produced must include the following:

- Qualified Dealer logo (if print ad or flyer)
- Promotion of natural gas and natural gas operated equipment only

Once all required conditions are satisfied, reimbursement is provided to the applicant for 50 per cent of the media insertion costs of advertising. Home Show booths are reimbursed for 50 per cent of their cost up to a maximum of $100.

There was a moderate uptake of participation in 2009 for the Co-op advertising program. The Companies are currently reviewing the structure and effectiveness of this program and will be making adjustments in 2010.

EFFICIENCY PARTNERS PROGRAM: NEW CONTRACTOR PROGRAM (2010)

Program Area(s): Residential and Commercial Energy Efficiency Programs

Target Market: Majority Residential & Minority Commercial

Duration: May 1st 2010 through April 1st 2011 (likely to be extended)

Objectives:

- Focus on the core of the contractor work force: licensed Gas Safety Branch B-ticket contractors serving residential and commercial end users
- TGI contractor Focus groups
- Develop new program

Program Details:

The first and second quarter program tasks include:

- Organize meetings in Vancouver, North Vancouver, Burnaby, Surrey, Kelowna, Kamloops and Prince George
- Compile feedback
- Plan program framework
- Determine qualification process
- Develop application forms
- Develop logo and brand
- Develop collateral such as brochures, advertisements, and web tile
- Facilitate outreach such as lunch and learns, speaking engagements and web ads
- Start New program registration

The third and fourth quarter program tasks include:

- Continue outreach to contractor associations
- Complete contractor registration
- EEC contractor workshops with Suppliers

Contractor program promotional activities will include:

- Direct contact with key individuals among target stakeholder groups (e.g. manufacturers, BC Safety Authority, etc).
- Engagement of suppliers and manufacturer's representatives via information sessions designed to instill awareness of, and answer questions about equipment options and our EEC programs.
- Lunch and learn sessions with plumbers and gas fitters.
- Speaking engagements and web page advertisements with target organizations such as:
    - BC Safety Authority (BCSA)

  - Thermal Environmental Comfort Association (TECA)
  - Mechanical Contractors Association (MCA)
- Magazine Advertisement with publications such as:
  - Hearth Patio Barbeque Association Canada (HPBAC) Magazine
  - Association of Professional Engineers and Geoscientists of British Columbia (APEGBC) Innovation magazine
  - American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Newsletter
- Upgrade the Terasen WEB search tool to enable customers to connect with service contractors in their service area.
- Bill insert promoting the new program service group

As identified in the contractor focus groups sessions of 2009, quarterly newsletters and cooperative supplier workshops will be the first steps taken to educating contractors about EEC program offers and the benefits of promoting energy efficiency.

PILOT STUDIES (2009)

Details of the 2009 Pilot Studies are described in this section. This includes:

- Okanagan Spray N' Save Pilot Program
- Furnace Servicing Pilot – "Give Your Furnace Some TLC" Campaign

PILOT PROGRAM: OKANAGAN SPRAY N' SAVE PILOT PROGRAM

Program Area: Commercial Energy Efficiency Program

Target Market: Commercial Retrofit

Duration: May - August 2009

Objective:

Run throughout summer 2009, in the Okanagan region, the Spray N' Save Pilot Program sought to achieve a reduction in natural gas consumption associated with the production of hot water by reducing hot water use in commercial kitchens.

Methodology:

TGI installed free of charge, new low-flow pre-rinse spray valves in willing food service facilities (i.e. restaurants, coffee shops, delis, groceries, etc.) in order to reduce the volume of hot water used in dishwashing.

TGI's program operator contacted food service operations, either by letter, in person or by telephone. Appointments were set up for the program operator to visit the establishment, and directly install, free of charge a new, low flow pre-rinse spray valve. The existing spray valve (s) were tagged and stored for six months, in case the establishment was not ultimately happy with the new valve. While on site, the program operator recorded site information such as flow rates before and after the installation, the water supply temperatures, business hours and the fuel source.

The program operator followed up with the food service operation after a certain period of time to determine the level of satisfaction with the new low flow pre-rinse spray valve. All recorded data was collected by TGI and a final report detailing the program operator's observations was produced.

PILOT PROGRAM: FURNACE SERVICING PILOT – "GIVE YOUR FURNACE SOME TLC" CAMPAIGN

Program Area: Residential Energy Efficiency Program

Target Market: TGVI Residential Retrofit

Duration: January 15, 2010 to June 30, 2010

Objectives:

- Educate customers about the importance of annual furnace servicing in terms of energy savings and reduced gas bills
- Promote contractor relations between TGVI and contractors, as well as between contractors and customers
- Promote appliance and equipment maintenance
- Determine how many participants require a furnace upgrade
- Provide an opportunity for contractors to identify further energy savings opportunities that customer could take advantage of
- Increase awareness of provincial and federal regulations regarding furnaces
- Determine the effectiveness of furnace servicing programs as a tool for educating residential customers about the need for maintaining appliances for optimal efficiency. Also engages contractors in dialogues about safety and the need to upgrade to high efficiency models.

Methodology/Communications Plan

Consumer-Response Marketing ("CRM") is handling program administration for the Furnace Servicing pilot. To receive the gift card, customers are required to submit their completed application, including the contractor's BC Safety Authority registration number and pertinent information about the furnace, along with a photocopy of the furnace servicing invoice.

Data gathered for the pilot is based on application form responses, and will be entered into the CRM database as applications are processed. CRM will provide bi-weekly program status reports, and will present a full report at the close of the program.

The TGVI furnace servicing pilot was promoted through the Terasen Gas website, bill inserts, radio, print advertisements in community newspapers, trade publications and contractor communications. The program was announced at the TGVI Contractors breakfast meetings in the first week of December 2010.

PILOT STUDIES (2010)

Details of the 2010 Pilot Studies are described in this section. This includes:

- Behaviour Change – Vancouver Coastal Health Authority and Providence Health Care staff engagement
- Behaviour Change – Destination Conservation for Public Buildings Pilot Program
- Domestic Hot Water Tier Three Technologies pilot
- Furnace Servicing Pilot – "Give Your Furnace Some TLC" Campaign
- EnerGuide 80 Pilot (Program in Development)

PILOT PROGRAM: BEHAVIOUR CHANGE - VANCOUVER COASTAL HEALTH AUTHORITY AND PROVIDENCE HEALTH CARE STAFF ENGAGEMENT

Program Area: Conservation Education and Outreach

Target Market: Approximately 28,000 staff members

Duration: September 2010 – August 2011

Program Objectives:

The goal of the program will be to pilot an online community site and develop an extensive employee engagement strategy that can eventually be implemented to other health authorities and/or large institutional customers. The focus of the campaign will be to promote and lead VCHA/PHC staff to participate in an online community site where opportunities will be available to learn about energy conservation, and make social commitments towards behavioural changes and GHG reducing actions. With this tool, the Companies hope to be able to investigate the attribution of energy savings to this behavioural program thus potentially providing a benchmark for capturing energy savings from our other education and outreach activities.

Methodology/Communication Plan:

The online tool will allow for staff to share ideas, compare usage with other coworkers, and focus on commitments at home and work, and will be promoted through lunch and learns, posters, contests both within and between facilities, e-newsletters and other methods. Costs associated with the initiative include the tool's licensing fees, consultant fees for development of the website, energy-related content and an engagement plan, and contest prizes. The website, content and engagement plan costs are a "one-time" cost, and once developed, the Companies intend to promote the program to additional Health Authorities and other large institutional clients, as well as our own employees.

PILOT PROGRAM: BEHAVIOUR CHANGE - DESTINATION CONSERVATION FOR PUBLIC BUILDINGS PILOT PROGRAM

Program Area: Conservation Education and Outreach

Target Market: Regional District Okanagan Similkameen, City of Penticton, District of Summerland, Town of Oliver, and Okanagan College Penticton Campus

Duration: March 2010 to February 2011

Program Objectives:

The goal of the project will be to find out if the combination of both low cost/no cost efficiency improvements and staff engagement in behavioural change will bring about energy reductions in municipal office facilities, and if energy saving reductions is achieved, the Companies will implement this program in other municipal customers.

Methodology/Communication Plan:

The project will include a strategy and training session, attitudinal and behavioural surveys of the staff before the project is implemented, energy assessments of the participating facilities, development of baseline energy consumption data for each facility, and a review of the empirical savings data at the end of the project.

Funding:

Project is jointly co-funded with FortisBC.

PILOT PROGRAM: DOMESTIC HOT WATER TIER THREE TECHNOLOGIES PILOT

Program Area: Residential Energy Efficiency Program

Target Market: Residential

Duration: April 1, 2010 through April 1, 2011

Objectives:

- Verify the actual energy savings associated with the Tier 3 technologies, as applicable to the Companies' service territory,
- Gather exhaust emission data and inlet gas flow rates,
- Determine GJ consumption relative to heated water volume,
- Identify water usage difference and introduce behaviour changes, while documenting results,
- Identify barriers to the installation and marketing of Tier 3 Technologies,
- Determine actual costs associated with the installation of condensing hot water tanks,
- Obtain feedback from a variety of stakeholders, including manufacturers, installers and end users, regarding the performance of Tier 3 Technologies,
- Determine if Meter changes are required with the higher demand loads, and
- Determine if incentive programs would be viable

The budget for the Tier 3 technologies pilot program is expected to be approximately $250,000 to cover the purchase and installation of 20 Tier 3 tanks, the purchase and installation of sub-metering devices for gas and water flow, and pilot program evaluation.

Background:

Tier 3 technologies are varied, but two important methods for achieving Tier 3 efficiency levels (EF 0.80 or greater) are condensing hot water tanks and tankless water heaters.

- A condensing water heater is similar to a standard efficiency gas storage water heater but has an improved heat exchanger that allows thermal efficiency ratings as high as 96 per cent and recovery rates as much as four gallons per minute. Condensing water heaters can deliver continuous hot water in high demand households. There are no residential condensing water heaters currently available for sale to consumers; however, GSW/John Wood has models that are appropriate for residential applications. It is estimated that the condensing water heaters will cost three to four times as much as standard efficiency water heaters.
- On-demand or "tankless" water heaters heat water only as it is needed and used. This equipment may incorporate condensing technology with resulting efficiencies higher than 90 per cent. The reports and supplier testing information in other jurisdictions regarding the energy savings for tankless or On-Demand Domestic Hot water systems are incomplete and lacking in value when comparing benefits over conventional hot water tank use.

Working with a variety of manufacturers, the Companies will measure the gas and water consumption in approximately 20 homes for 6 months, installing the Tier 3 technologies after 3 months, and measure the difference in energy consumption between the 3 months prior to installation and the 3 months following the installation of the Tier 3 tanks. The Tier 3 Technologies pilot program is in the early design stages and the structure of the program is subject to change, based on feedback from industry, manufacturers, and contractors.

PILOT PROGRAM: ENERGUIDE 80 PILOT

Program Area: Residential Energy Efficiency Program

Target Market: Residential Retrofit and New Construction

Duration: January 2010 through April 1, 2011

Objectives:

- Support early adoption of new building code standards which would move the current EnerGuide 77 efficiency rating to a new target of EnerGuide 80 for new home construction
- Provide existing gas heated homeowners with incentives to perform efficiency upgrades that result in EnerGuide rating improvements

Methodology:

The following quarterly milestones outline the pathway to assessing and developing the EnerGuide 80 Retrofit and New Home Construction program.

The following are activities for Q1 & Q2 of 2010:

- Review and evaluation of Home Energy Assessment process with Service Organizations, NRCan and MEMPR.
- Review verification testing of random assessments performed by NRCan.
- Work with Certified Energy Advisors (Service Organizations) to upgrade delivery of Assessment services.
- Work with NRCan and ENERGY STAR® to establish rating levels for BC zones.
- Undertake Hot 2000 Modeling to establish correlations that relate, comparative GJ savings, guidelines for a prescriptive upgrade, and resultant target EnerGuide ratings
- Evaluate results and develop incentive program based upon results of California Standard Practice tests.

The following are activities for Q3 and Q4 of 2010:

- Introduction of Whole Home Labeling and possibly ENERGY STAR® levels.
- Run pilot with that validates EnerGuide rating increments with each step outlined in the prescriptive path guidelines.
- Based on results of modeling, pilot, and stakeholder feedback, rollout Residential EnerGuide Home Retrofit and New Construction Program

Incentives for retrofits in the EnerGuide 80 program will focus on moving older houses up the EnerGuide scale. Each time a home energy assessment is conducted, the home is given an EnerGuide rating. Rebate programs related to home energy assessments, such as Natural

Resource Canada's ecoEnegy program, require an assessment both before and after retrofits have been completed. The EnerGuide 80 program would assign incentives based on the number of points a house moves up the EnerGuide scale. For example, if a home begins at EnerGuide 66 and after the various energy efficient upgrades have been completed it moves to EnerGuide 76, the customer would receive an incentive for having increased their EnerGuide rating by 10 points.

Given that this program is in the early stages of development, it requires discussions with a large number of stakeholders. The Companies are evaluating available market and technical data to establish a sound business case and cost benefit analysis. Therefore, performance metrics for this program are not available at this time

Background:

EnerGuide home efficiency performance levels are determined by performing Home Energy Assessments. The Energy Assessment process, software and quality of audit results are managed by Natural Resources Canada and the Ministry of Energy Mines and Petroleum Resources. A home's energy efficiency level is rated on a scale of 0 to 100. A rating of 0 represents a home with major air leakage, no insulation and extremely high energy consumption. A rating of 100 represents a house that is airtight, well insulated, sufficiently ventilated and requires no purchased energy on an annual basis.

Older homes need periodic renewal of major energy efficiency components including windows, heating, and fresh air ventilation systems, so the actual score of a 20-year-old home will depend in large part on whether these systems have been updated or are original.

As new building codes will not take effect until mid 2011, now is the time to encourage builders and developers, through incentives, to begin building homes to the EnerGuide 80 standards. Ideally, incentives will help builders and developers define the prescriptive measures that will achieve EnerGuide 80 standards, and prepare the market for the new building code changes.

Appendix E

CONSERVATION FOR AFFORDABLE HOUSING

Conservation for Affordable Housing

The following section includes details relating to activities within the Conservation for Affordable Housing programs area. This includes:

- LiveSmart Carry Over Buildings and Measures
- Members of the BC Working Group for Energy Efficiency for Affordable Housing
- Members of the Affordable Energy Conservation Task Force
- Attendees at the 2009 Affordable Energy Conservation Forum

LiveSmart Carry Over Buildings and Measures

The LiveSmart Carry Over project included complete energy efficiency retrofits in five affordable housing complexes throughout Metro Vancouver. The buildings and efficiency measures for this program are shown below.

SOCIAL HOUSING PROVIDER	Address	# of Units	Energy Assess.	Installs	Total	Measures
MVHC Meridian Village town homes	3156 Coast Meridian Rd, PoCo	129	$ 17,415	$ 219,300	$ 236,715	For each unit: showerheads, kitchen aerators, programmable thermostat, weather-stripping, draft-proofing, ventilation and attic insulation
Hoy Creek MURB	2905 Glen Dr V3B6E5 & 1205 Johnson, Coq	97	$ -	$ 150,341	$ 150,341	For each unit: showerheads, kitchen aerators, programmable thermostat, weather-stripping, draft-proofing, ventilation and attic insulation
Collingwood Village Co-op MURB	5398 Tyne Street, Vancouver	79	$ 12,713	$ 134,300	$ 147,013	High-efficiency gas boiler and multiple other measures as funds allow.
Kilarney Gardens Co-op MURB	2998 East 54th Ave, Vancouver	227	$ -	$ 382,021	$ 382,021	For each unit: showerheads, kitchen aerators, programmable thermostat, weather-stripping, draft-proofing, ventilation and attic insulation
Burlington Heights MURB	1865 E 10th Ave, Vancouver, V5N 1X8	25	$ 7,213	$ 42,500	$ 49,713	High-efficiency gas boiler and multiple other measures as funds allow.
Totals		**557**	**$ 37,341**	**$ 928,462**	**$ 965,803**	

Members of the BC Working Group for Energy Efficiency for Affordable Housing

The following is a list of the organizations that are represented on the BC Working Group for Energy Efficiency for Affordable Housing. Each of these organizations have at least one person representing their organization. There are a total of 29 individuals on the Working Group and no more than two people from any one organization.

	Company
1	Active Support Against Poverty
2	BC Housing
3	BC Hydro
4	BC Non-Profit Housing Association
5	BC Public Interest Advocacy Centre
6	BC Sustainable Energy Association
7	City Green Solutions
8	City of Vancouver Sustainability Division
9	CMHC
10	Co-operative Housing Federation of BC
11	EAGA Canada
12	FortisBC
13	Fraser Basin Council
14	Indian and Northern Affairs Canada
15	Ministry of Energy, Mines & Petroleum Resources
16	Northern Resources Canada
17	Tenant Resource & Advisory Centre
18	Terasen Gas
19	TRAC Tenant Resource & Advisory Centre
20	Vancity

Members of the Affordable Energy Conservation Task Force

The following is a list of the organizations that are represented on the Affordable Energy Conservation Task Force. Each of these organizations have at least one person representing their organization. There are a total of 10 individuals on the Task Force and no more than two people from any one organization.

	Organization
1	BC Hydro
2	BC Non-Profit Housing Association
3	BC Public Interest Advocacy Centre
4	City Green Solutions

	Organization
5	Eaga Canada
6	Fraser Basin Council
7	Ministry of Energy, Mines and Petroleum Resources
8	Terasen Gas

Attendees at the 2009 Affordable Energy Conservation Forum

The Affordable Energy Conservation Forum hosted a total of 83 people from the following 47 organizations.

Organization
Active Support Against Poverty
Adams Lake Indian Band
BC Citizens for Public Power
BC Housing
BC Hydro
BC Non-Profit Housing Association
BC Public Interest Advocacy Centre
BCIT student
BCSEA
British Columbia Utilities Commission
Canadian Centre for Policy Alternatives
Canim Lake Band
Capital Region Housing Corporation
Carrier Chilcotin Tribal Council
Carrier Sekani Tribal Council
City Green Solutions
City of North Vancouver
CMHC
Concert Properties (speaker)
Cooperative Housing Federation of BC
Council of Senior Citizens' Organizations of BC (COSCO)
eaga Canada
Earth Festival Society

Organization
ENVIRON
Family Services of Greater Vancouver
FortisBC Inc.
Fraser Basin Council
Fraserside Community Services Society
Gwawaenuk Tribe
Kibo Ventures Inc.
Lonsdale Energy Corp
Metro Vancouver
MOSAIC
Nicomen Band
OnPoint Consulting Inc.
Pacific Northern Gas Ltd.
RESORT MUNICIPALITY OF WHISTLER
Simon Fraser University
Skeetchestn Indian Band
Social Planning and Research Council of BC
Terasen Gas
The Elizabeth Fry Society
Tla-o-qui-aht First Nation
TRAC Tenant Resource & Advisory Centre
T'SOU-KE NATION
Vancity
Whistler Housing Authority

Appendix F

EEC STAKEHOLDER GROUP

EEC STAKEHOLDER GROUP

As discussed in Section 4.9, the Companies recognized the need for accountability in the EEC Application and proposed to form and engage an EEC Stakeholder Group. The objectives of the EEC Stakeholder Group are to guide and provide input on EEC activity. The corresponding invitation, agenda, priorities, and minutes from both the December 9, 2009 and March 11, 2010 meetings are included in the Appendix.

LIST OF EEC STAKEHOLDER MEMBERS (AS OF MARCH 11, 2010)

Member	Organization	Title
Marg Gordon	B.C. Apartment Owners and Managers Association	Chief Executive Officer
Steve Hobson	BC Hydro	Director Power Smart
Rob Noel	BC Mechanical Contractors Assoc	Commercial contractors
Eugene Kung	BC Public Interest Advocacy Centre	Barrister & Solicitor
Wayne Lock	BC Safety Authority	Operations Manager
Alison Richter	BC Utilities Commission	Regulatory Analyst - First Nations and Sustainability
Tammy Jackson	Canadian Home Builders' Association Central Okanagan	Executive Officer
Vanessa Joehl	Canadian Home Builders' Association of BC	Built Green™ BC Program Administrator
Marni Vistisen	City of Prince George	Energy Coordinator
Mark Hartman	City of Vancouver	Buildings Energy Programs Manager
David Craig	Consolidated Management Consultants	President
Joan Huzar	Consumers Council of Canada	
Dan Pasacreta	Crosby Property Managements, Ltd	Licensed Strata Agent
Keith Veerman	FortisBC	Manager-Energy Efficiency
Bob Purdy	Fraser Basin Council	Director, External Relations & Corporate Development
Amy Spencer-Chubey	Greater Vancouver Home Builders' Association	Director of Government Relations
Bruce Macgowan	IBC Technologies Inc.	President
Erik Kaye	Ministry of Energy, Mines and Petroleum Resources	Acting Manager, Energy Efficiency Policy
Nir Kushnir	National Energy Equipment	General Manager, Trane
John Cockburn	Natural Resources Canada	Senior Chief, Equipment Standards and Labelling Housing, Building and Regulations
Elizabeth Westbrook	Natural Resources Canada	Senior Officer, Stakeholder Relations
Nina Winham	New Climate Strategies	Consultant and Rate 1 customer
Al Kemp	Rental Owners and Managers Society of BC	CEO
Cindy Stern	Tseshaht First Nation	Chief Operating Officer
Jeff Fischer	Urban Development Institute	Deputy Executive Director

Terasen Gas

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
Fax: (604) 576-7220
Toll Free: 1-800-773-7001
www.terasengas.com

November 13, 2009

Dear Stakeholders and Interested Parties:

Re: Terasen Gas - Energy Efficiency & Conservation Stakeholder Group

This year Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively "Terasen Gas") received approval from the British Columbia Utilities Commission ("BCUC") for an expanded Energy Efficiency and Conservation ("EEC") portfolio to provide customers with enhanced tools and incentives to manage their natural gas consumption, reduce their energy costs, and lower their greenhouse gas emissions. The newly approved $41.5 million portfolio includes rebates and incentives on a number of energy efficient appliances, equipment and systems, as well as educational and outreach initiatives for residential and commercial customers, and those customers in the affordable housing sector.

Terasen Gas recognizes the need for accountability for the approved funds and believes that engaging an EEC stakeholder group would be beneficial to guide and inform EEC activity. We are seeking representation from the following areas:

- Provincial, municipal, and First Nation governments
- Non-Governmental Organizations
- Consumer advocates, representing residential customers
- Affordable housing advocates
- Commercial customers
- Trade organizations
- Equipment manufacturers
- Other utilities

To add transparency and accountability to our EEC portfolio, we intend to hold bi-annual EEC workshops with stakeholders, at which we will present updates on program progress and monies allocated. The one-day workshops would also act as a forum for stakeholder input on developing new programs and refining existing programs.

The first stakeholder meeting proposed will be either **Tuesday December 8** or **Wednesday December 9, 2009** in Vancouver.

We respectfully invite your participation in Terasen's EEC Stakeholder Group. Please contact me via email at jenny.chia@terasengas.com or via phone 604.592.7645 if you are interested in joining the Terasen EEC Stakeholder Group or if you have any questions. If you require financial and booking assistance with travel arrangements from outside the Lower Mainland, we would be pleased to assist you with those. Please confirm your participation in the Terasen EEC Stakeholder Group by **Monday November 23, 2009.**

Regards,

Jenny Chia

Jenny Chia
Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.

Agenda
EEC Stakeholder Meeting
December 9, 2009
Sheraton Wall Centre, Port Alberni Room
1088 Burrard St, Vancouver

8.30 – 9.00	***Registration and Breakfast***
9.00 – 9.15	Welcome from Terasen
9.15 – 9.30	Roundtable Introductions of Stakeholder Group
9.30 - 10.00	What is Demand Side Managment (DSM)
10.00 – 10.30	Integrated Resource Planning and DSM
10.30 – 10.45	***Break***
10.45 – 11.30	Terasen's EEC Application
11.30 – 12.00	Terasen's Historical DSM Program Results and DSMS
12.00 – 12.45	***Lunch***
12.45 – 13.15	Government Regulations
13.15 – 13.30	Introduction to New EEC Programs
13.30 – 14.00	Post-EEC Residential Programs
14.00 – 14.30	Post-EEC Commercial Programs
14:30 -14:45	***Break***
14.45 – 15.15	Post-EEC Affordable Housing Programs
15.15 – 15.30	Contractor Program
15.30 – 15.45	Conservation Education and Outreach
15.45 – 16.15	Wrap-up

TERASEN GAS ENERGY EFFICIENCY & CONSERVATION STAKEHOLDER MEETING MINUTES

DECEMBER 9, 2009

Attendees

Alison Richter, British Columbia Utilities Commission, Regulatory Analyst – First Nations and Sustainability

Amy Spencer-Chubey – Greater Vancouver Home Builders' Association, Director of Government Relations

Bridget Macgowan - IBC Technologies, CFO

Casey Edge - CHBA Victoria, Executive Director

Cindy Stern – Tseshaht First Nation, CEO

Dan Pasacreta – Crosby Property Management, Licensed Strata Agent

David Craig- Consolidated Management Consultants, President

Erik Kaye – Ministry of Energy, Mines, and Petroleum Resources, Acting Manager, Energy Efficiency Policy

Jen Richards – City of Vancouver, Sustainability, Program Assistant

Keith Veerman – FortisBC, Manager – Energy Efficiency

Kevin Kwok – City of Vancouver, Manager, Environmental Services

Marni Vistisen, City of Prince George, Energy Manager

Nir Kushnir – National Energy Equipment, General Manager (Trane)

Rob Noel – BC Mechanical Contractors Association, Commercial Contractors

Steve Hobson – BC Hydro, Director Power Smart

Vanessa Joehl – CHBA-BC, Built Green BC Program Administrator

Terasen Gas Staff

Beth Ringdahl

Dave Bennett

Doug Stout

Jenny Chia

Ken Ross

Gary Lengle

Lee Robson

Michelle Petrusevich

Ned Georgy

Negar Ghavami

Paola Blendl

Ramsay Cook

Samuel Nyabando

Sarah Smith

Shawn Hill

Regrets

Al Kemp, Rental Owners and Managers Society of BC

Angela Reid, City of Kelowna, Councillor

Eugene Kung, BC Public Interest Advocacy Centre, Barrister & Solicitor

Jeff Fischer, Urban Development Institute, Deputy Executive Director

John Cockburn, Natural Resources of Canada, Senior Chief, Equipment Standards and Labeling Housing, Building and Regulations

Mark Hartman, City of Vancouver Sustainability, Building Energy Programs Manager

Sharon Slager, CHBA Northern BC, Executive Director

Tammy Jackson, CHBA Central Okanagan, Executive Director

Shawn Hill, Manager Regulatory Affairs

Why is DSM Important

1) Does the recession have an impact on the price?
    a. The supply is there to meet demand
2) Is natural gas priced on a national (Canadian) or global basis?
    a. Historically (early 2000's), oil and natural gas were substitutes→ global and interchangeable
    b. As the price of natural gas decouples from that of oil, gas has become a North American market
    c. AECO is priced on Canadian price for GJs
    d. Long term, resources are there to produce gas
    e. Is there a demand to justify further extraction? It is a very efficient market

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Ken Ross, Resource Planning Analyst

Integrated Resource Planning

1) How does the Integrated Resource Planning stakeholder group compare and contrast with other stakeholder groups that Terasen might be convening?

a. EEC group is designed to give us feedback about the overall EEC portfolio and input as to whether we are moving in the right direction with the programs we are putting together
b. The Integrated Resource Planning stakeholder group: Are our assumptions in the planning environment the same as what our stakeholders see?

Sarah Smith, Manager, Marketing & Energy Efficiency

EEC Overview

1) Does the EEC Application incorporate LiveSmart BC?
   a. No. We were contributing $250 to the LiveSmart furnace incentive, but we also offer the funace incentive separate from LiveSmart
2) On what basis did the BC Utilities Commission scale back the request?
   a. In regulatory processes, there are a number of people that intervene.
   b. Certain customers do not want their money spent on EEC activities, because the funding comes from rate increases.
3) Innovative technologies and trade relations was denied
   a. There are certain benefit/cost thresholds that have to pass
   b. Innovative technologies have very long paybacks
   c. Trade relations: funding was included in the non-incentive budgets that were put forward
   d. We have incorporated trade relations in other areas of our EEC budget

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Michelle Petrusevich, DSM Program Development Lead

Historical Program Results and DSMS

1) How were the Destination Conservation savings projected?
   a. Evaluation report conducted by a consultant suggests that each school saves 113 GJs per year
   b. No savings attribution to behavior changes as a result of the program
   c. Behavioural change brought about through education
2) What have you learned about incentives regarding DSM? What motivates/ drives EEC/DSM decisions?
   a. Residential: biggest reason for change in consumption is financial incentive, environment is far down the list (from Residential End Use Study)
   b. Communications is key
   c. Commercial: we don't have a lot of research in that area yet
3) How do you broaden conservation and sustainability and make the messaging appealing to different audiences?
   a. Take other factors into consideration, besides financial
   b. Health and environmental benefits
   c. Have not yet promoted health benefits and used illness to pitch the case

    d. Our experience in commercial efficiency, we concentrate on investment and payback → Reference BC Hydro lighting program
4) Will a new tracking system be able to provide feedback to contractors and manufacturers?
    a. We have the ability to do so today, but need feedback on whether or not to do it share that information with manufacturers (eg. Market share of furnaces by manufacturer)
5) Will there be a financing program for customers (residential?)
    a. We don't have the capability to do it with our current Customer Information System
    b. The new Customer Information System, which we are including in the current Customer Care Enhancement Application, can do it
    c. Terasen asked in application for an extra body to research and design a financing program
    d. Terasen could see that as an extension of our business
        i. E.g. Terasen Energy Systems: we own the system and make them pay back over bills (strata example of extending gas lines into homes)
    e. Government looking at options where homeowners moving can get their home labeled (Prince George labeling pilot)
    f. Recognized need for financing, but the question is whether or not the utility should be involved
    g. Manitoba Hydro example

Erik Kaye, Acting Manager, Energy Efficiency Policy

Government Regulation

1) Post 2012, where is government policy going regarding carbon tax and regulation? Is there room for discussion and negotiation between Terasen and gov't to map that out?
    a. Absolutely. Government meets with utilities frequently to discuss policy initiatives like fuel choice, role of NGVs, DES, etc.
2) What messaging does the government want contractors to convey when talking to homeowners? This is a sensitive question: customers see BC Hydro and Terasen Gas as one bill. Heat pumps are the most common installation, should customers be going electric?
    a. We want to convey energy efficiency and conservation
    b. Reducing greenhouse gas is the imperative, so we don't want people to switch to higher carbon fuels. However, we don't want everyone going electric.
3) There is a concern about increasing the efficiency of homes through retrofits without due diligence (no educational or financial considerations).
    a. Homeowners are taking permits, and not knowing what they're doing
    b. Professional builders sometimes don't have the appropriate training
    c. Renovators are not properly educated or licensed
    d. Government is working on a comprehensive strategy on building capacity to make sure workmanship aligns with code
    e. Terasen also has a concern about training, which is why we're engaging with the housing branch and supporting Energy Efficient Building Strategy, and building capacity
4) There is a shift to electric technology and the government seems to be supporting that.
    a. e.g. LiveSmart heat pump has a larger incentive
    b. Manufacturers are confused on what to recommend to customers

c. Natural gas and electricity markets operate differently and market prices do not normally reflect what is best

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Beth Ringdahl, EEC Program Manager, Residential

Residential Programs

1) Who is eligible for the furnace scrap it program (e.g. what about firehalls? residential or commercial?)
    a. We may not have to limit it to one market
2) Discuss SPIFF (ie. sales person incentive) process with BC Hydro
    a. Pat Mathot has had success with SPIFF uptakes
3) Dishwasher program:
    a. Similar to Powersmart incentives but for customers with gas hot water

4) Consumer awareness and demand for tankless heaters increasing, so why don't we have an incentive for them?
    a. We have not found any independent third party evidence suggesting they save energy/money
    b. North America is the only place that still sell hot water tanks
    c. Potential for TG to partner up with manufacturers to find conclusive data
5) Audit (Eco-energy) project:
    a. NRCan putting in $225 million for project
    b. Cost of the audit process is unnecessary. Some customers just want to purchase a new appliance and the government is spending all this money on an audit unnecessarily
        i. The idea is that customers get the benefit of a 'whole home' audit. They will maybe upgrade other parts of their home.
6) Furnace scrap it- why do you need incentives?
    a. We want to encourage early retirement.
        i. Need to do market research prior to starting program design – what do folks plan to do in the face of the introduction of the EE regulations
        ii. Anecdotally we are hearing about stock piling of mid efficient furnaces
        iii. Lots of people do not know about the regulation: we need to build awareness
    b. Fundamental economics: to stop them from coming back into the market. Issue→ what is the curve/ resistance look like?
        i. How long are the units going to be there?
        ii. Portfolio level TRC
        iii. Average furnace is in for 13 years
        iv. Can we provide incentive for upgrading the infrastructure since new venting sometimes needs to be put in?
7) Scrap it program
    a. How are the old furnaces disposed? Are they recycled? Will be investigated as part of program design.
    b. Scrap it for boilers as well? Yes
    c. Replace furnace→ very complex process
        i. Need a consumer portal: average customer can get info easily
    d. Many of the program application processes are also too complex and admin heavy for contractors (too much bureaucracy)
    e. Lighting program has been successful but struggled at the beginning

i. There is a balance between simplicity and due diligence (spending money wisely)

Ramsay Cook, EEC Program Manager, Commercial

Commercial Programs

1) What is the market momentum with efficient hot water heaters?
    a. Biggest barrier is the upfront capital cost
    b. Lack of awareness that there is an economic Net Present Value
    c. Tankless water heaters are covered as long as they are energy efficient (94%)
    d. Incentives are significant enough to consider uptake
    e. Working on simplifying process
2) Commissioning- some LEED buildings are using more energy as a result of operations
    a. LEED study- some LEED buildings are using up to 27% more energy than standard buildings
    b. There is a current misconception of what LEEDS is→ LEED ≠ energy efficient. Building may be LEED for proximity to transportation, building materials, etc.
3) What about a Pre Rinse Spray Valve program for restaurants?
    a. Terasen Gas ran a Pilot Program in the Interior and Okanagan in 2009
    b. Best run in geographic pockets
    c. Currently are running some measurement and verification tests for the Okanagan spray valve program

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Ned Georgy, EEC Program Manager, Conservation for Affordable Housing

Conservation for Affordable Housing Programs

1) What are the opportunities in First Nation new housing?
    a. Terasen's focus has been retrofits in current housing due to high energy savings
    b. Build housing through Canada Mortgage and Housing Corp on tight budgets ($40K)
    c. Usually multiple homes, which has economies of scale
    d. But contractors are forced to choose cheapest routes
2) First Nations talk to each other, work with administrator
3) How do you get program participation in First Nations?
    a. Lots of forums
    b. Lots of social marketing and word-of-mouth
4) Many manufacturers have programs tailored to low income households→ the problem is clarifying what project qualifies
    a. There is a potential for partnership with Terasen
    b. The larger the savings, the more willing manufacturers are to participate
5) Good idea to let administrators know about programs because they hire contractors
6) Criteria for programs
    a. Need regulatory reform on new projects
    b. Gear programs to zoning/regulation change
    c. e.g. Habitat for humanity in Saanich
    d. caution of stepping into world of social policy tools because we are an investor-owned utility
7) Who is the target audience in conservation for affordable housing?
    a. Certain percentage are provided by public housing and social conscience or are renters

b. Energy Savings Kits → not expensive for us to produce
c. Energy Conservation Assistance Program → some mechanisms in place for landlord to sign contract to not increase rent
d. Problem→ slum landlords
    i. Get landlord advisory (residential tenancy branch) involved
    ii. Rent controls provide some incentive (increase margins).
e. There are many associations out there: Rental Owners and Managers Society of BC, BC Hydro split incentives group

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Gary Lengle, EEC Program Manager, Qualified Dealer Program

Efficiency Partners Program

1) Challenges in up-selling energy efficient appliances:
    a. Consumers feel the contractor is trying to up-sell them
    b. Consumers have more info thanks to the internet and are educated
    c. Customers trust utilities. Having the Terasen brand will give some credibility
2) Can we roll out programs earlier than Q4? Even if it's not perfect?

Jenny Chia, EEC Communications, Education & Outreach Manager

Conservation Education, and Outreach

1) Can Terasen attend Victoria Spring Home Show?
    a. Not this year. Simply a matter of lack of resources and Olympic timing (hard to commute)

EEC Stakeholder Meeting Agenda
March 11, 2010
Hyatt Hotel
655 Burrard St, Vancouver – Stanley Room

9:30 - 9:45	Registration (coffee served)
9:45 - 10:00	Welcome and Agenda
10:00 - 10:15	Roundtable Introduction
10:15 -11:15	Stakeholder Workshop: Sharing goals and priorities
11:15 – 11.30	TG topic: Alternative Energies Solutions
11:30 – 12:00	TG topic: Innovative Technologies
12.00 – 12.45	Lunch
12.45 – 14:00	2009 Annual report review and 2010 Update
14:00 -14:15	Break
14:15-15:00	Stakeholder Dialogue: Setting Action
15:00-15:15	Closing

Terasen Gas Energy Efficiency & Conservation Stakeholder Meeting
March 11, 2010

Attendees

Al Kemp, Rental Owners and Managers Society of BC
Alison Richter, British Columbia Utilities Commission, Regulatory Analyst – First Nations and Sustainability
Amy Spencer-Chubey – Greater Vancouver Home Builders' Association, Director of Government Relations
Bob Purdy, Fraser Basin Council
Bruce Macgowan - IBC Technologies
Cindy Stern – Tseshaht First Nation, CEO
Dan Pasacreta – Crosby Property Management, Licensed Strata Agent
David Craig- Consolidated Management Consultants, President
Elizabeth Westbrook-Trenholm, Natural Resources Canada, Office of Energy Efficiency, Stakeholder Relations
Erik Kaye – Ministry of Energy, Mines, and Petroleum Resources, Acting Manager, Energy Efficiency Policy
Jeff Fischer, Urban Development Institute, Deputy Executive Director
Jen Richards – City of Vancouver, Sustainability, Program Assistant
Joan Huzar, Consumers Council of Canada
Marg Gordon, BC Apartment Owners and Managers' Association
Mark Warren – FortisBC
Nina Winham, New Climate Strategies; Terasen Gas rate 1 customers
Nir Kushnir – National Energy Equipment, General Manager (Trane)
Steve Hobson – BC Hydro, Director Power Smart
Wayne Lock, BC Safety Authority, Gas Operations Manager

Regrets

Eugene Kung, BC Public Interest Advocacy Centre, Barrister & Solicitor
Mark Hartman, City of Vancouver Sustainability, Building Energy Programs Manager
Marni Vistisen, City of Prince George, Energy Manager
Rob Noel – BC Mechanical Contractors Association, Commercial Contractors
Vanessa Joehl – CHBA-BC, Built Green BC Program Administrator

Terasen Gas Staff

Beth Ringdahl	Ned Georgy
Jenny Chia	Ramsay Cook
Ken Ross	Sarah Smith
Gary Lengle	John Turner
Michelle Petrusevich	Doug Tufts
Arvind Ramakrishhnan	Mark Grist
Shawn Hill	

John Turner
Alternative Energy Solutions

(no questions)

Doug Tufts
Arvind Ramakrishhnan
Innovative Technologies

Q: Do programs have to be for upgrading?
: Solar can be for new or retrofit; hydronic, new; NGVs can be converted

Q: Why is there less money for TGVI?
a. Dollars is proportionally based on the # of customers we have on TGVI

Q: Referring to the City of Vancouver example, if I understand correctly, if solar is required in regulation, then Terasen is not going to fund it, is that the position?
a. The new buildings just have to be solar ready (ie. Piping), but don' t have to have the solar system installed
b. Utilities cannot provide incentive if it is regulated

Discussion on free riders
Q: What about municipal regulations?

a. Utilities still might advance adoption of regulation but if customer had to put one in, it would be hard to argue that utility incentive had any help with that.
b. Provincially, government is also trying to raise the bar to meet municipal regulations and not have widely diverse buildings. It's a whole market transformation and not just in isolation.
c. Terasen can comment on municipal policies and how affect programs

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Michelle Petrusevich
Structure and Overview of EEC report

(no questions)

Beth Ringdahl
Residential Programs

Scrap It Furnace – need to get stakeholder feedback on program and need to see what market is like for mid-efficient furnaces

Switch 'n' Shrink – under Fuel Switching in the report. 70% of the participants are from TGVI

Whole Home program – under joint initiatives in the report.

Hot water tank program – hard to get industry information, such as lit of eligible models from manufacturers. Terasen would like to put on directory on the website of eligible models.

Ministry policy on storage tanks have to be 80%; currently condensing storage tanks do no exist in the market today.
Q: in regulation, is BC unique?

a. First in North America; NRCan will be joining in later on. We have ambitious targets. How do we move manufacturers move this along, so need to work with utilities. We don't have the option of waiting.
b. There is a 6-12 month delay product delay from US to Canada.
c. There is a caution in mixing storage and non storage tank issues (are apples vs. oranges)

Q: What is the definition of residential customer?

a. SFDs, mobile homes, and townhomes; multi-family is considered commercial customer
b. There is multi-family homes on oil in Vancouver Island – can apply for Switch 'n' Shrink?
c. Maybe those home can apply for Efficient Boiler Program

Ramsay Cook
Commercial Programs

Q: Are there any absolute caps on funding on custom design program? How are savings measured?

a. About $3/GJ, but will not pay 100%
b. Each project will have to pass a TRC test
c. Will benchmark against energy study, then look at meter and energy consumption

Q: Will the study capture waste heat?

a. Terasen is open to study, we are just trying to get GJ savings

Q: have you looked at purchasing managers as a key audience, they are very risk adverse people and only look at costs involved?

a. Terasen can do education with purchasing managers.

Ned Georgy
Conservation for Affordable Housing

Q: In regards to ReNEW, is there continued training past 2010?

a. Looking to work with some groups on Vancouver Island.

Q: How do you choose participants for the program?

a. Partners choose because they know their audience.

Q: Who is doing the SEMP study? BC Non Profit or City Green?

a. BC Non Profit Housing Association; City Green is involved in all 3 studies. Studies have partners in sharing the cost.

Gary Lengle
Efficiency Partners Program

(no questions)

Jenny Chia
Conservation Education & Outreach

Q: Co-op on tradeshows?

a. Possibly, Terasen has to look it over.

Q: Is there a possibility of using the Pembina tool to train sales associates (ie. At big box stores)?

a. Yes

Stakeholder Action List (roundtable around the room)

Jeff at UDI – look at educating members on incentives and regulation

Al at ROMS BC – look at manufacturer home parks – they are out of the loops. Possibly have a joint Terasen and BC Hydro info session for ROMS for their board/industry

Marg at BCAMOA – provide info in newsletters to members, and include info at board meeting on Wed Mar 17.

Bob at Fraser Basin Council – get in touch with Terasen manager on NGVs

Joan at Consumers Council of Canada – likes the home (energy) labeling idea because it's a good way of letting consumers know

Amy at GVHBA – get together with Beth, Ned, and Jenny and discuss GVHBA opportunities. GVHBA also has a monthly newsletter where info can be placed.

Cindy at Tseshaht First Nation – go back to the community, communicate about Terasen programs for people that are not in social housing; will be speaking about Terasen at national Aboriginal Housing Forum in Calgary

Wayne at BC Safety Authority – is concerned about contractors not having the skill set to install the new technology/equipment; have to look at training and if need to upgrade training, perhaps suppliers should provide training for installers

Terasen Gas EEC Stakeholder Meeting – Stakeholder 2010 Priorities
March 11, 2010

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Greater Vancouver Home Builders' Association	-protecting interests of new home buyers -housing affordability and choice -education -marketing and networking	700+ members Builders Developers Trades Suppliers Architects & designers →Voice of residential construction industry	-reduce/prevent downloading of chares to the price of new homes -promote voluntary market driven green building -underground economy that do not get a permit for renovations	-programs for new home buyers, specifically first – timers -invest in innovative/alternative energy solutions	-continue green incentive programs -educating trades -reno program -consumer behaviour cultural shift -investment for alternative energy solutions
BC Apartment Owners and Managers' Association	-sector sustainability through offering lobbying, education, partnerships with affiliates and associates (price points) -member strength through retention and grown	3000 members Apartment owners & managers (landlords) + associates (suppliers) + affiliates -sustainability	-member education -member retention -member growth -partnership programs to assist members -energy savings; renovations and greener technology -find landlords and hot to reach them	-partnership in education, affiliation, sponsorship -news posts on web, magazine & newsletter -info on present & future opportunities -incentives/split	-workshops and tailor to high rise members, medium buildings, and low rise members -news blasts -intro of new programs -change behavior → how do we make the new "bling" energy efficiency?

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
National Energy Equipment (distributor of Trane)	-increase market creation of home comfort systems for retrofit market -incorporate “clean air” offering into heating and cooling products	-(52) HVAC dealers -homeowners that purchase Trane equipment	-improve quality of installation of Energy Star products -clarify the energy saving message with homeowners	-Terasen dealer (contractor) program -promotions planned outside of the “high season” (Sept –Nov) because impacts quality of installation	-consider “Terasen partners” program on the distribution level (eg. advertising) -work with the NRCan -align upcoming programs with homeowners’ needs and understand consumer mindset
BC Utilities Commission	-increase stakeholder engagement -increase knowledge and capacity in new areas of responsibility, not just an economic regulator		-build capacity/knowledge in commissioners and staff on DSM/energy efficiency best practices from other jurisdictions	-EEC meetings continue -provide updates, feedback and engage with Commission -keep doing what you’re doing	
Consumers Council of Canada	-consumers more aware of energy efficiency options -consumers knowledgeable about the costs/payback/justification of energy efficient purchases -ensure the consumer voice is at the policy table	-residential consumers of energy	-energy efficiency adopted as an objective in building codes -understand consumer attitude to energy efficiency -consumer protection available + accessible to consumers (remedies)	-perhaps a partnership to enable us to get consumers’ opinion/feedback on energy issues + housing issues -access to info on the residential consumer + their preferences & actions (take up of incentives?) -get info to customers	-meet with appropriate Terasen reps to talk about possible options

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Urban Development Institute	-to connect our industry with governments and the public -improve our industry through professional development and education -having a reasonable cost of & regulatory environment for our members	Developers & professionals that support them. -500 corporate members (architects, engineers, banks)	- housing affordability -reducing cost (fees, charges imposed by government -greenbuilding sustainability	-research/education on cost effective green build, energy efficiency, sustainable tools, technologies (how much customers value/do not value on e.e. to potentially support a salesperson education initiative -need consistent approach; various Lower Mainland municipalities are too diverse in policies on sustainable buildings -incentives for our members (green technologies have high upfront costs)	-information -education
Crosby Property Management	-energy savings -green technology	25,000 residential strata owners	-hold costs or do better -looking for incentives -HRTC did a lot in 2009	-information to customers	-timers for fireplaces for strata owners (program)
IBC Technologies	-expand condensing boiler product offering into commercial sizes/markets -more residential market choices with different price points/affordability	-IBC -Canadian Hydronics Council (BC rep) -CSA TC on energy efficiency	-see goals -evolve commercial boiler efficiency measurement standards	-provide clarity on DSM programs and changes thereto -host local roundtable meeting of stakeholders to commercial boiler efficiency issues to take to the national meeting	

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Natural Resources Canada	-improve Canadians' energy consumption practices in commercial and institutional buildings to the end of reduced GHGs (17% by 2020)	Government of Canada	-encourage energy efficiency retrofits and new building design -commissioning and re-commissioning -update energy code -develop bench marketing-data for buildings (offices and schools) -position for transition to post 2011 (funding ending) -build capacity among energy professionals -update the Model National Energy Code for Buildings for release 2012	-information sharing -partnerships/cooperation on optimizing resources in program design/delivery -liaise with regional stakeholders (oversee all of Western Canada)	-develop working groups?
Consolidated Management Consultants	-fair and cost effective supply	-represent commercial energy consumers	-continue to consult with BC Hydro and Terasen Gas -challenge anything that is less than cost effective -success in meeting government's goals-see utilities in succeeding	-consultation on EEC -interested in alternative energy -long term plan for reducing GHGs (by 2050) -interested in cost effective management in utility -continued engagement	
Rate 1 customer/landlord/ New Climate Strategies consultant	-improve energy efficiency infrastructure in my home	-rate 1 customers across BC	-learn about insulation options (for old home) -improve hot water systems - too much waste	-help me assess opportunities in a comprehensive way (not one-off technologies) -expertise for hire, who can assess my options?	-work with BC Hydro to give me coordinated picture of my energy and GHG issues

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Rental Owners and Managers Society of BC	-continue growth to 2400 members -achieve changes to residential tenancy act -increase recognition of rental industry as provider of homes to 1/3 of British Columbian	-2200 residential owners and managers -50,000 rental homes	-increase awareness of ROMS BC among BC's landlords	-recognize distinctiveness & size of residential rental industry +/- 600,000 rental homes -apartment buildings are different from condos or SFDs	-tenants consume, landlords pay??
City of Vancouver	-reduce GHGs -meet community based action goals	-municipality and Vancouver residents	-MURBs and small – businesses -retrofit program (under consideration, require at least 10% of the cost of any permitted renovation to be allocated to e.e. upgrades using prescriptive measures)	-for SFDs – prescribed measures, or Energuide rating -COV support by having green renovation guides online	-example of laneway house with computer interface that indicated energy usage
Ministry of Energy, Mines and Petroleum Resources	-energy efficiency -reducing GHG emissions -develop a culture of conservation		-Energy Plan -Climate action -Clean energy economy	-support for codes and standards -integration with LivesmartBC -innovation with gas (NG vehicles) -communicate with Energuide 80 -go beyond code, maybe home labeling	

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Tseshaht First Nation	-expand economic development and diversification -expand member employment opportunities -improve quality of life-industry housing -building relationships with Alberni Valley Community	1000 members 750 on reserve	-building 14 new houses (need for 80 families housing—multigenerational, increased growth in community with declining growth in neighbouring community) -7 new RAPS (renovations) -develop partnerships for tourism projects -encourage entrepreneurship -support building of new athletic hall in Port Alberni -new ventures + construction eg. greenhouse	-partnerships for training and mentoring -grants for new athletic hall (gas powered new construction) -seeking appliance bundles for energy efficiency in new houses -cost efficiency and energy efficiency	-do not understand using natural gas on reserve, mainly BC Hydro
Fraser Basin Council	Vision: strong communities, healthy ecosystems and vibrant economies in the Basin and beyond Goals: climate change mitigation/adaptation (reducing GHGs/energy efficiency) -smart planning for communities -regional and sub-regional (local) issue resolution -aboriginal engagement	-all form orders of Canadian government including First Nations + private sector + community/civil society interests	-continue to build on successes: -green fleets BC initiative, transportation -energy solutions for remote communities -supporting community energy planning though BC –demand side management -supply chain Buymost program	-harness power of strategic relationships; facilitate and bring together unlikely parties -multi-interest board	-continuing to build bridges between people, organizations, regions – and action items together

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
City of Prince George	-climate change goals & objectives that relate to participation in the Partners for Climate Protection Program (PCP). -the goal is a 10% reduction in greenhouse gas emissions from 2012, from a benchmark year of 2002. actively involved in meeting a target of carbon neutral operations by 2012 under the Province's Community Action Charter -20% reduction in overall energy intensity (electricity & natural gas) by 2015 (5 years) -5% reduction in overall energy intensity (electricity & natural gas) for each facility in 2010	-citizens of Prince George	-5% reduction in energy intensity for 2010 -carbon neutral by 2012 -10% Reduction in GHG emissions by 2012	-GHG emissions and energy consumption: easily accessible programs to help decrease GHG emissions, and funding that is available to retrofit old equipment, or implement a project that will decrease natural gas consumption would be appreciated.	

Note: priorities missing from BC Hydro, FortisBC, BC Public Interest Advocacy Centre, Canadian Home Builders' Association of BC, BC Mechanical Contractors Association,, and BC Safety Authority.

Appendix G

EFFICIENT BOILER PROGRAM TERMS AND CONDITIONS

Efficient boiler program

Terms and conditions

Table of contents

The incentives

Efficient boiler incentives are made up of two parts: a purchase incentive which is based on the type of boiler purchased, plus either; a new constriction incentive; or a retrofit incentive.

Purchase incentive

For all participants, the incentive applies to the incremental purchase price of a natural gas near-condensing or condensing boiler over the purchase price of a standard-efficiency boiler. The purchase price incentive is based on space heating and ventilating load. They will be calculated as follows:

- near-condensing boilers: $4,000 per boiler plus $3 per MBH plant input
- condensing boilers: $6,000 per boiler plus $9 per MBH plant input

The purchase price of a standard-efficiency boiler will be estimated using $7 per MBH of the input required to meet the space heating load.

In addition to the purchase price incentives above, Terasen Gas will also contribute additional incentives to your upgrade project as outlined below.

New construction

Terasen Gas will contribute 50 per cent of engineering fees to a maximum of $1,500 toward the cost of estimating the annual gas usage for space heating using a standard-efficiency boiler system versus a higher efficiency boiler system. Purchase price incentive payments are limited to a maximum of 75 per cent of the purchase price premium over a standard boiler.

Retrofit of existing buildings

The program will pay your contractor up to a maximum of $400 for performing an estimate of the peak space heating load. It will also pay 50 per cent of the cost of necessary venting modifications up to a maximum of $2,000. During the first year of operation you are also entitled to a monitoring incentive of $1,500 plus $1 per gigajoule of total natural gas saved. Purchase price incentive payments are limited to a maximum of 50 per cent of the purchase price premium over a standard-efficiency boiler.

The benefits

Ongoing savings of up to 40 per cent

- operating savings from lower natural gas expenditures
- greater potential savings if boilers are also used for domestic hot water heating

Higher performance

- improved operating efficiency through correct boiler sizing
- improved reliability if a modular boiler system with multiple boilers is used

Energy efficiency assistance

- assistance in determining your facility's potential for energy improvements
- help in finding ways to save money and improve your facility's operation

Space efficiency and comfort

- requirement for less space in mechanical rooms
- excellent opportunity to increase occupant comfort and reduce building maintenance and operating costs to end buyers

Increased marketability

- improved efficiency appealing to customers who recognize the value it adds to their investment
- increased value of your development
- competitive advantage over other projects

Environmental benefits

- fewer CO, CO_2 and NOx emissions into the atmosphere
- responsible use of a clean burning natural resource

Program terms and conditions

Note: Subject to change without notice.

1.0 Overview

1.1 The Efficient Boiler Program (the program) from Terasen Gas Inc. (Terasen Gas) is designed to stimulate investment in appropriately sized energy-efficient space heating boilers that will reduce natural gas usage and associated operating costs. The program is targeted to both new construction and replacement markets.

1.2 The program offers all market participants an incentive payment to partially offset the higher purchase price of higher efficiency boilers, a contribution to the cost of accurately estimating the building's space heating load.

1.3 In new construction, the program contributes to the engineering fees for estimating the building's annual natural gas usage for space heating with a standard efficiency boiler and comparing it to that with a higher efficiency boiler. It also partially offsets the higher boiler purchase price incurred by a developer, builder or owner. Terasen Gas will also recognize the developer's, builder's or owner's commitment to energy efficiency on behalf of tenants, end users and subsequent owners.

1.4 In the replacement market, the program compensates a mechanical contractor to accurately estimate the peak space-heating load. It also reduces the building owner's higher purchase price for an energy-efficient boiler, including an allowance for required venting upgrade modifications. It also promotes proper ongoing operation and maintenance of the heating plant to reduce annual space heating costs, maintain efficiency and lower life cycle costs by paying building owners a monitoring incentive and a natural gas-saving bonus.

1.5 By taking part in this offer, your boiler may use less natural gas and produce fewer emissions. You agree Terasen Gas Inc. may record any resulting emission reductions you have along with those of other participating customers and credit them to our Greenhouse Gas Management Program.

2.0 Participant eligibility criteria

2.1 The applicant must be a building developer, builder, building owner or owner's designated representative.

2.2 The facility where the boiler is installed must be in the Terasen Gas service territory in the Lower Mainland, Vancouver Island, Sunshine Coast, or the Interior of BC. (Not available in Whistler).

2.3 The facility where the boiler is installed must use natural gas purchased according to one of the following Terasen Gas Rate Schedules: 2, 2U, 3, 3U, 23, 5, 25, AGS, SCS-1, SCS-2, LCS-1, LCS-2 or LCS-3.

2.4 Only eligible boilers under the program qualify for the incentive (see section 4.0 for the boiler eligibility criteria).

2.5 The incentive will only be paid for space heating boilers. When the boiler is used for space heating as well as other applications such as domestic hot water and pool heating, the domestic hot water load and the pool heating load will be subtracted from the boiler input to determine the space heating load for incentive calculations.

2.6 Standby or backup space heating boiler plants will not normally qualify under this program. Standby or backup boilers are defined as boilers that normally only operate during peak heating load. However, a boiler plant that is not the primary source (i.e. does not provide over 50 per cent) of space heating for the facility, can qualify if the facility uses natural gas for domestic hot water and make-up air units.

3.0 Program process

All market participants

3.1 Applicant's contractor or qualified professional determines the capacity of the space heating plant, type of boiler (i.e. condensing or near-condensing), capacity and number of boilers required to meet the space-heating requirements of the building.

3.2 Applicant completes Efficient Boiler Program Application Form and submits it along with required documentation (7.0) to Terasen Gas.

3.3 Terasen Gas reviews application for completeness.

- (i) If application is complete, Terasen Gas estimates the incentive that is payable to the applicant.
- (ii) If application is incomplete, Terasen Gas will ask applicant for additional information.
- (iii) If required documents are not completed and submitted within one month of the application date the application may be cancelled.

3.4 Applicant receives a letter from Terasen Gas stating whether the application was approved or rejected. If approved, an estimate of the incentive(s) payable to the applicant will be attached to the letter.

3.5 Applicant purchases and installs the boiler within 12 months from the date of approval (3.4) by Terasen Gas.

3.6 Applicant submits required documentation to Terasen Gas within one month of boiler installation. (See Section 7.0 for documentation).

3.7 Terasen Gas reviews documents for completeness.

- (i) If all documents are in order and the applicant has met all the requirements of the program and the boiler capacity has not changed from original application, Terasen Gas issues a boiler incentive cheque to the applicant.
- (ii) If all documents are in order and the applicant has met all the requirements of the program, but the installed boiler capacity and/or purchase price has changed since the application was first submitted, Terasen Gas recalculates the incentive and issues a cheque for the revised boiler incentive.

New construction market participants

3.8 The contribution of Terasen Gas to the engineering fees required to estimate annual gas usage will be included in the boiler incentive cheque issued to the applicant.

Replacement market participants

3.9. The contributions of Terasen Gas to the contractor's cost to estimate the peak space heating load, and to the cost of the required venting upgrades, will be included in the boiler incentive cheque issued to the applicant.

3.10 Terasen Gas will send the reporting requirements for the monitoring incentive and gas-saving bonus to the applicant with the incentive cheque.

3.11 Applicant prepares the reports that are required for the monitoring incentive and gas-saving bonus.

3.12 Applicant submits the reports to Terasen Gas. One report is submitted six months after boiler installation; the second report is submitted 12 months after boiler installation.

3.13 Terasen Gas reviews the reports for completeness.

- (i) If applicant meets the reporting requirements, Terasen Gas calculates the monitoring incentive and gas-saving bonus and issues a cheque. Cheque is issued after Terasen Gas receives the two complete sequential six month reports.
- (ii) If applicant has not met the reporting requirements, Terasen Gas advises applicant that reporting requirements have not been met and applicant does not qualify for monitoring incentive and gas-saving bonus.

4.0 Eligible boilers

All boilers

4.1 Must be a natural gas space heating boiler system (propane boilers in Revelstoke can also qualify). Multiple boiler modules housed in a single jacket constitute one boiler.

4.2 The minimum boiler input rating is 300,000 Btu/hr.

4.3 The maximum boiler input rating is 5,000,000 Btu/hr.

4.4 The minimum space heating plant input rating is 300,000 Btu/hr.

4.5 The maximum space heating plant input rating is 10,000,000 Btu/hr.

4.6 The incentive will only be paid for space heating boilers. (see section 2.5 for details).

4.7 Boiler efficiency ratings must be independently tested in accordance with BTS-2000 Testing Standard for Efficiency of Commercial Space Heating Boilers from the Hydronics Institute Division of GAMA (www.gamanet.org) or CSA 4.9 Gas-Fired Low Pressure Steam and Hot Water Boilers.

4.8 Third party documentation of boiler combustion efficiencies must be provided for boiler eligibility. Acceptable documentation includes either

(i) combustion efficiency test reports from testing laboratories accredited by the Canadian Standards Association (CSA International) or the American National Standards Institute or from the Hydronics Institute Division of GAMA;

(ii) a combustion efficiency certification letter from CSA International; or

(iii) inclusion in the I=B=R Ratings for Boilers, Baseboard Radiation and Finned Tube (Commercial) Radiation Directory, January 2008 Edition, with the steady state combustion efficiency rating published in the directory
(www.gamanet.org).

4.9 Boiler must be installed in accordance with the manufacturer's specification and must comply with applicable laws, codes, standards and ordinances.

4.10 The boiler must be new. Used or rebuilt boilers do not qualify for the incentive.

4.11 Boilers must be covered by a standard or optional minimum two-year parts and labour warranty.

Near-condensing boilers

4.12 Definition of near-condensing boiler:

(i) has a minimum steady state combustion efficiency of 85 per cent as tested throughout the turn down range in accordance with BTS-2000[i] or CSA 4.9[ii]

(ii) has a factory installed intermittent ignition

(iii) has a forced draft or induced draft burner that properly controls excess air

(iv) conforming boilers will have continuous capacity modulation (not staged burner output control) to
enable operation at reduced output down to 50 per cent or less of maximum continuous output. This turndown will be achieved by continuously varying fuel and air input quantities

Condensing boilers

4.13 Definition of condensing boiler:

(i) has a minimum steady state combustion efficiency of 88 per cent throughout the turn down range as tested in accordance with BTS-2000[i] or CSA 4.9[ii]

(ii) a Category IV boiler that vents through a Class II Type BH stack or a stack that complies with the manufacturer's recommendations

(iii) conforming boilers will have continuous capacity modulation (not staged burner output control) to enable operation at reduced output down to 50 per cent or less of maximum continuous output. This turndown will be achieved by continuously varying fuel and air input quantities

(iv) the boiler can continuously withstand heating system return water temperatures that do not exceed 49°C

List of eligible boilers

4.14 A list of eligible boilers is available on our website at terasengas.com. This list may be updated during the course of the program.

i - BTS 2000 Testing Standard for Efficiency of Commercial Space Heating Boilers, Hydronics Institute Division of GAMA - 2000

ii - Gas-Fired Low Pressure Steam and Hot Water Boilers, Canadian Standards Association

5.0 Incentives

All market participants

5.1 Boiler purchase price incentives will be calculated as follows:

(i) near-condensing boilers: $4,000 per boiler plus $3.00 per MBH plant input for space heating load

(ii) condensing boilers: $6,000 per boiler plus $9.00 per MBH plant input for space heating load

5.2 The purchase price of a standard efficiency boiler will be estimated using $7.00 per MBH of input for space heating load.

5.3 The boiler purchase price is the applicant's purchase price of the boiler net of any vendor rebates excluding installation labour, venting and accessories.

5.4 Terasen Gas reserves the right to limit the number of incentive payments it provides for the program.

New construction market participants

5.5 In new construction, Terasen Gas will pay 50 per cent of a qualified professional's fees to compare the estimated annual natural gas usage for space heating using a standard efficiency boiler to that with a higher efficiency boiler to a maximum of $1,500. This will be payable to the applicant at the time the boiler purchase price rebate is paid to the applicant and will not be paid unless an eligible boiler is actually installed. Proof of payment must be submitted with the application. The energy modelling must be completed by a qualified professional using DOE, EE4, TRACE, HAP or equivalent program and must compare the space heating energy use of the building using a standard efficiency boiler and a higher efficiency boiler.

5.6 In new construction, boiler purchase price incentive payments are limited to a maximum of 75 per cent of the premium over a standard efficiency boiler.

Replacement market participants

5.7 In replacement applications, Terasen Gas will pay a maximum $400 of the cost incurred to estimate the peak space heating load. This will be payable to the applicant at the time the purchase price incentive is paid and will not be paid unless an eligible boiler is actually installed. Proof of payment must be submitted with the application.

5.8 In replacement applications, boiler purchase price incentive payments are limited to a maximum of 50 per cent of the premium over a standard efficiency boiler.

5.9 In replacement applications, the total amount of the boiler purchase price incentive and the venting replacement incentive is subject to a maximum limit equal to the price of the installed boiler.

5.10 In replacement applications, Terasen Gas will pay a monitoring incentive of $1,500 plus $1/GJ of gas-saving bonus for each GJ of annual weather-normalized reduction in total natural gas consumption. The weather-normalized gas consumption in the 12-month period following the boiler installation will be compared to the weather-normalized gas consumption during the 12-month period prior to the boiler installation. The applicant must report the data from the following inspections:

(i) perform combustion analysis and record combustion efficiency, $\%CO_2$, $\%O_2$, ppm NO_X and flue gas temperature every six months

(ii) perform a diagnostic check of the controls weekly

(iii) perform visual check of system components weekly

(iv) record boiler water outlet temperature weekly

(v) record boiler water inlet temperature weekly

(vi) record boiler room temperature weekly

5.11 Applicant must submit reports that include the data listed above to Terasen Gas six months and 12 months after the boiler installation to qualify for the monitoring incentive and gas-saving bonus.

6.0 Additional terms and conditions

All market participants

6.1 One application form must be submitted per each gas account (gas meter) in your facility, that serves the qualifying boiler plant or plants you want to apply for.

6.2 The building's heat load must be calculated and the heating plant must be sized in accordance with ASHRAE Standard 90.1 to ensure the heating plant is not oversized.

Equipment requirements

6.3 HVAC systems must be sized to meet the needs of the conditioned spaces.

6.4 Equipment installed outdoors or in unconditioned spaces must be designed by the manufacturer for such installation.

6.5 HVAC equipment and components included in the scope of Model National Energy Code for Buildings (MNECB) Table 5.2.13.1 must comply with the relevant local appliance/equipment energy efficiency act or the relevant standard listed.

Hydronic systems

6.6 All hydronic systems must be designed so they can be balanced.

6.7 Multiple boiler systems must prevent heat loss through boilers when they are not in operation through the use of such items as draft dampers or shut-off valves interlocked with burners.

6.8 Pipes containing fluids with design operating temperatures outside the 13°C to 40°C range must be insulated as per MNECB Table 5.4.2.3. Some exemptions apply.

6.9 Boiler hot water distribution piping outside the building envelope must be insulated to the maximum requirements as per MNECB Table 5.4.2.3. Insulation must be protected where it may be subjected to mechanical damage, weathering or condensation.

6.10 Seasonal pumping systems, such as heated and chilled water pumping systems, must have automatic controls or readily accessible and clearly labelled manual controls to shut down the pumps when they are not required.

Additional requirements

6.11 All boiler installations with a maximum rated input of 400,000 BTU/hr or higher must be approved by the BC Safety Authority. (See 7.2 (ii))

6.12 The manufacturer or an authorized factory representative must either perform or supervise equipment start up and provide a written report to Terasen Gas indicating that the installation meets manufacturer's requirements. The report must include:

(i) boiler inlet return water temperature °C

(ii) boiler outlet supply water temperature °C

(iii) boiler room temperature °C

(iv) exhaust gas temperature °C

(v) %CO_2 in the exhaust

(vi) %O_2 in the exhaust

(vii) % steady state combustion efficiency

(viii) boiler clocked firing rate (Btu/hr)

6.13 The applicant agrees to periodic inspections of the applicant's premises by Terasen Gas or its representative to verify that the boiler has been installed and is in operation, and to cooperate with Terasen Gas thereafter to gather information necessary to assess the success of the program.

6.14 Applicant agrees to allow Terasen Gas to publish their business name, a general description of the system upgrade undertaken and resulting energy performance and payback period.

New construction market participants

6.15 In new construction, a qualified professional must be retained to estimate:

(i) the facility's peak space heating load based upon the January 2.5 per cent °C winter design temperature for your location (reference Table C-2 National Building Code)

(ii) a standard efficiency boiler's peak annual gas consumption (GJ)

(iii) the higher efficiency boiler's annual gas consumption (GJ)

Replacement market participants

6.16 In replacement markets, the contractor must prepare an estimate of the facility peak space heating load based upon the January 2.5 per cent °C winter design temperature for your location (reference Table C-2 National Building Code).

Program deadlines

6.17 The program, including the eligible boiler criteria and eligible boiler list, may be amended or modified at any time without notice and the program may be terminated at any time without notice.

6.18 Funding for this program is limited. Terasen Gas may, in its sole discretion, determine how this funding will be shared between the new construction market and the replacement market. This may mean that Terasen Gas will continue to accept new construction market applications after the program has been terminated for the replacement market or the converse.

6.19 Applications must be submitted to Terasen Gas and pre-approved by Terasen Gas prior to the purchase and installation of the boiler.

6.20 Final documents must be submitted within one month of boiler installation.

6.21 If Terasen Gas amends or modifies the program after an application is received and pre-approved by Terasen Gas, the applicant cannot resubmit an application for the same boiler plant under the amended or modified program.

Representations and warranties

6.22 Applicant acknowledges the program eligibility criteria and warrants that it fully qualifies and will comply with such criteria.

6.23 Applicant warrants that all information contained in the application and the information attached thereto is true and correct.

6.24 Applicant covenants that it will notify Terasen Gas immediately if there is any material change in the application and information attached thereto after it is approved by Terasen Gas.

6.25 Applicant acknowledges that by taking part in the program, their boiler may use less natural gas and produce fewer emissions. Applicant agrees that Terasen Gas may record any resulting reductions in emissions along with those of participating customers and credit them to the Terasen Gas Greenhouse Gas Management Program.

Default or fraud

6.26 The incentive approved is based on the information in the application documents. If there are any changes to the information in the application documents after it is approved, Terasen Gas in its sole discretion may void the application documents and Terasen Gas will be released from any and all obligations under the program.

6.27 Applicant agrees to the terms and conditions of the program. If the applicant fails to perform according to these terms and conditions, then upon notice of default from Terasen Gas, the applicant shall refund the full amount of the incentive upon request from Terasen Gas.

Liability

6.28 Terasen Gas shall have no ownership interest in the boiler.

6.29 Terasen Gas, not being the designer or manufacturer of the boiler, makes no representation or warranty, express or implied as to the fitness, design or capability of the material, equipment or workmanship in the boiler, nor any warranty that the boiler will satisfy the requirements of any law, specification, or contract, which may be made against or incurred by Terasen Gas, its contractors, agents and employees in any way relating to, or arising out of, the program.

6.30 Applicant indemnifies and saves harmless Terasen Gas, its contractors, agents, and employees from all liability and all claims, damages, expenses and costs.

6.31 Terasen Gas does not endorse any particular manufacturer, product, system, design, supplier or installer in promoting the program.

Tax implication

6.32 Terasen Gas will not be responsible for any tax liability imposed on the applicant as a result of payments of the incentive. For GST Registrants, incentives received by the applicant include GST which must be remitted by the applicant to the Receiver General of Canada.

7.0 Documentation

All market participants

7.1 Terasen Gas is not responsible for lost, delayed, damaged, illegible or incomplete applications.

7.2 The following documents must be submitted to Terasen Gas:

(i) prior to approval:

- completed application form

(ii) after boiler installation:

- a confirmation letter must be submitted stating that the boiler(s) have been installed
- the following documents must be submitted with the confirmation letter:
- gas permit and, if applicable, an approval certificate with a Certificate of Inspection from the BC Safety Authority
- copy of the start up report by the manufacturer or an authorized factory representative
- copy of boiler and vent material sales invoice

New construction market participants

7.3 The following documents from a qualified professional must also be submitted within one month of the date of application prior to approval otherwise the application may be cancelled.

(i) estimate of the peak space heating load

(ii) report on projected natural gas usage for space heating

(iii) invoice for completing the report on projected natural gas usage for space heating

(iv) proof the invoice has been paid

Replacement market participants

7.4 The following documents from the contractor must also be submitted within one month of the date of application prior to approval otherwise the application may be cancelled.

(i) estimate of the peak space heating load

(ii) invoice for completing the estimate of the peak space heating load

(iii) proof the invoice has been paid

7.5 The following documents must also be submitted after boiler installation:

(i) confirmation letter must be submitted indicating the interest to participate with the monitoring phase of the program

(ii) first report with the data from Section 5.10 above must be submitted 6 months after boiler installation

(ii) second report with the data from Section 5.10 above must be submitted 12 months after boiler installation

8.0 Contact information

Toll-free: 1-888-477-0777

Fax: 1-604-576-7122

E-mail: rebates@terasengas.com

Mail: Efficient Boiler Program
Technical Sales Support
Terasen Gas
16705 Fraser Highway,
Surrey BC V4N 0E8

Appendix H

INTERNAL AUDIT SERVICES EEC PROCESS AND INTERNAL CONTROL REVIEW

Terasen Gas Inc. & Terasen Gas (Vancouver Island) Inc.
Energy Efficiency and Conservation Program
- Process and Internal Control Review

Distribution to:

- Randy Jespersen, President & Chief Executive Officer
- Scott Thomson, VP, Regulatory Affairs & Chief Financial Officer
- David Bennett, VP, General Counsel & Corporate Secretary
- Doug Stout, VP, Marketing & Business Development

Internal Audit Services
Terasen Inc.

March 1, 2010

Background

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. ("The Companies") Energy Efficiency and Conservation Program ("The Program" or "EEC") is designed to provide customers tools and incentives to manage their natural gas consumption, reduce their energy costs, and lower their greenhouse gas emissions.

In April 2009, the British Columbia Utilities Commission ("BCUC" or "Commission") granted the Companies approval for the Program expenditure of $41.5 million for the period 2008 to 2010. This is a significant expansion from the Companies' previous EEC activities which had remained largely unchanged since the late 1990's at the incentives and non-incentive expenses level of approximately $1.50 million and $1.624 million respectively for TGI and $650k and $500k respectively for TGVI. The Program includes rebates and incentives on a number of energy efficient appliances, equipment and systems as well as education and outreach initiatives to increase awareness of the energy efficiency and environmental benefits that can be achieved by using clean burning natural gas in high efficiency appliances.

Review Scope and Objectives

Given the recent expansion of the EEC activities, the review provides a timely opportunity to assess the effectiveness of current processes and controls and to recommend improvements during the transitional period of the Program.

The objective is to evaluate the design effectiveness of the project management processes and controls as established for the facilitation of the Program. The following will be evaluated as part of the review:

- Identify key risks and determine whether risks are appropriately managed;
- Review existing policies, procedures and practices with reference to best practices;
- Review the level of adherence to and compliance with existing policies and procedures;
- Develop recommendations and potential action plans to address any significant issues or opportunities for improvement that are identified; and
- Review for compliance with the BCUC Decision.

Project Risks

IAS developed a risk-based audit approach to review key processes and evaluate internal controls for the Project. The following risks that may result in cost overruns and jeopardize the success of the project were considered:

- *Cost Monitoring:* Program costs are not monitored and analyzed on a timely basis resulting in cost overruns with the amount not recoverable;

- *Scheduling:* Program is not delivered on time; program objectives are not met; changes to schedules are not properly communicated;
- *Authorization:* Improper authorizations resulting in program delays and/or overcharges or improper charges for program costs;
- *Invoice Payments:* Invoice payments are not in accordance with contract terms and do not match contracted deliverables;
- *Program administration:* Administration of various EEC programs are not monitored for accuracy and efficiency as well as adherence to terms and conditions of the program resulting in program cost overruns, administrative inefficiencies and participant ill will; and
- *Reporting:* Project reporting fails to supply appropriate measurement for management of cost, scope and schedule to ensure proper management oversight.

Summary of Observations

The EEC Team has demonstrated good project commitment with the common goal of achieving the Program's objectives in the most cost effective and efficient manner. As this is a significant increase in funding for the EEC program, internal controls need to be robust to ensure the program is managed effectively.

Certain internal controls for the Program were established and implemented but, IAS has determined that there are opportunities to improve processes or internal controls. The details are reported to management in a list of observations and recommendations attached to this report. The summary of the significant opportunities are as follows:

- ***Process and Control Documentation:*** Process and internal control documentation for various EEC programs was not readily available. Timely communication of process and controls is critical to achievement of program objectives, especially given that a significant number of the EEC team consist of new employees.
- ***Third-Party Program Administration:*** Some of the EEC programs are administered by third-parties; however, their performance was not often monitored by Terasen. Based on IAS' sample testing, some instances of exceptions in program administration were noted. A periodic review of the effectiveness of third party administrators is recommended to ensure that quality of the program administration is acceptable. Also noted was that one EEC program did not have a statement of work in place with one third-party program administrator. Each EEC program should have a statement of work in place with any third party administrators prior to program commencement to establish terms and conditions in administering the program.
- ***Internal Program Administration:*** Based on IAS' sample testing, one incident was noted where an application approved did not follow terms and conditions of the program. Also, for one of the EEC programs there was no clear evidence of review performed on applications and the review did not consider all areas of potential risk. Adherence to program terms and conditions, documentation of evidence of review and consideration of all risk areas when performing review are recommended.

- ***Program Status Reporting:*** Currently there is no formal reporting on the EEC program progress in place. It is recommended that regular update of program progress is reported to the appropriate level of management and personnel for timely monitoring of the programs.

Our findings have been presented to management and we are satisfied with their response to improve processes and internal control.

Opinion

In my opinion, the processes and the design of internal controls surrounding the Program receives an assessment of Yellow[1]. We found no major weaknesses in the process and control environment, but there were sufficient minor weaknesses requiring prompt management action to address the recommendations made to adequately mitigate the associated risks being managed.

Andrew Lee CA-CIA
Manager, Internal Audit Services
Terasen Inc.
March 15, 2010
Burnaby, BC

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Green	We found no/very few weaknesses and we recommended no (or only minor) improvements.
Yellow	We found no major weaknesses in the control environment, but there were sufficient minor weaknesses requiring prompt management action to address the recommendations made.
Red	We found a major weakness (or several minor weaknesses combined) in an operation or process in which the control environment (or lack of) and/or testing results indicate a significant risk or exposure to the company.

Observations and Recommendations

#	Observations	Risk	Recommendations	Management Response
1.	**Process and Control Documentation** Process documentation for various EEC programs was not readily available. The approved business case cannot be relied upon for details of internal control within the process.	Internal controls that are not established may impede achievement of program objectives.	Communication of process and controls prior to the program commencement is critical to achievement of program objectives. This is especially true as a significant number of the EEC team consist of new employees.	Process and control documentation will be updated and provided to personnel. Internal control documentation will be incorporated into the business case for programs on a go forward basis with assistance from IA on a program by program basis. **Management Accountability:** Sarah Smith, Manager, EEC **Estimated Timing:** on-going
2.	**Third-Party Program Administration** A significant number of EEC programs are administered by third-parties. A review of various programs and related applications resulted in the following exceptions: a) Energy Star Heating System Upgrade – Terasen Accenture Business Services for Utilities (ABSU) had the following exceptions: • Of 24 sample application forms requested, 5 were not available • 6 did not contain evidence of review performed by ABSU • Through discussion, it was noted that the Statement of Work (SOW) Agreement expired in 2007 and has not been renewed b) Energy Star Heating System Upgrade – LiveSmart • Ministry of Energy Mines and Petroleum Resources (MEMPR) does	Payments made to ineligible participants	A periodic review of the effectiveness of third party administrators to ensure accurate and efficient program administration should be performed. Terasen is ultimately responsible for all EEC programs and should be diligent in ensuring that quality of third-party program administration is acceptable. A statement of work should be established with each third-party to outline terms and conditions in administering programs. A right to audit clause should be part of the contract.	This will be implemented for all third party administrator contracts entered into on a go forward basis. **Management Accountability:** Sarah Smith, Manager, EEC Beth Ringdahl, EEC Program Manager (Residential) Ramsay Cook, EEC Program Manager (Commercial) **Estimated Timing:** March 15, 2010

#	Observations	Risk	Recommendations	Management Response
	not provide application documentation c) EnerChoice Fireplace • One incident was noted where there were two consecutive application reference numbers assigned to the same participant but only one invoice with one fireplace purchase was available for both applications. Since both applications were approved and paid, duplicate payment is suspected. d) EcoEnergy Home Energy Assessment (D-Visits) Program – LiveSmart BC • MEMPR does not provide application documentation			
3.	**Internal Program Administration** A review of various programs and related applications resulted in the following exceptions: a) Efficient Boiler Program (EBP) • One incident was noted where an applicant had installed a boiler prior to obtaining pre-approval to be eligible for the rebate application. This is not in accordance with the Program's terms and conditions, which states the pre-approval must be obtained prior to boiler installation. Per discussion there have been a few other cases where applicants installed boilers prior to obtaining pre-approval and accepted to the program. Reasons included a need for a new boiler due to an emergency or learning about the program after installing the boilers. b) Light Commercial Energy Star Boiler Program • There was no clear indication a review	Ineffective application evaluation process can result in payments to ineligible participants.	a) Adherence to program terms and conditions should be followed. b) It is recommended that evidence of review should be documented. While the risk of duplicate applications was low based on the small number of participants in 2009, management should consider its implication on a go forward basis as more participants are expected.	a) Terms and conditions for the pre-approval requirement has been modified and eliminated for new applicants b) All internal reviewers are now required to initial applications as evidence of review. **Management Accountability:** Sarah Smith, Manager, EEC Beth Ringdahl, EEC Program Manager (Residential) Ramsay Cook, EEC Program Manager (Commercial) **Estimated Timing:** March 2, 2010

#	Observations	Risk	Recommendations	Management Response
	was performed on the application (e.g. initials). • Based on discussion, it was noted that the current application evaluation process did not include a process to detect any duplicate applications.			
4.	**Participant Database Management – Efficient Boiler Program (EBP)** It was noted that the current participant database contained a number of inactive accounts - some dating back to 2005. Prior to October 2008 the program allowed participants up to 2 years from the application pre-approval date to install boilers. This resulted in administrative difficulties in keeping up-to-date with status of some accounts. The program terms and conditions have been revised since to allow participants 1 year to install boilers. However, the database has not been updated to remove inactive participants.	Database containing inactive participants can result in inaccurate reflection of program performance as well as impede the effectiveness of program management	The program database should be updated to reflect the accurate status of accounts participating in programs.	EBP administration has been re-patriated to the EEC Dept, and the Database will be updated. **Management Accountability:** Sarah Smith, Manager, EEC Ramsay Cook, EEC Program Manager (Commercial) **Estimated Timing:** March 31, 2010
5.	**Demand Side Management (DSM) Cost-Benefit Model** There are two sets of DSM Cost-Benefit models that are used by the EEC team. One is a "program planning" model that is used by EEC Program Managers during program development for scenarios planning and supports the Business Case that is eventually signed by Management in accordance with the Signing Authority protocols established within the Company. The other is the Total Resource Cost (TRC) reporting spreadsheet that is used by the Business Development Analyst to create large-scale spreadsheets that support Annual Reporting to external stakeholders and the BCUC. • In both cases, input cells that are constant formulated cells are not protected • For the "program planning" model, there is no controls process to check accuracy of formula on a regular basis.	There is risk that the Models can be accessed and modified by unauthorized individuals.	Implementation of the following controls into the Models are recommended: • Cells that are constant in the "program planning" model should be protected to prevent unauthorized modifications • Access to the large-scale spreadsheet that is used for external reporting should be password protected and restricted to the Manager, EEC and the Business Development Analyst	Administration of the spreadsheets will incorporate the recommendations. **Management Accountability:** Sarah Smith, Manager, EEC Arvind Ramakrishnan, Business Development Analyst **Estimated Timing:** March 31, 2010

#	Observations	Risk	Recommendations	Management Response
	This is not the case for the large-scale spreadsheet that is used for Annual Reporting, which is checked over by an external consultant prior for use to support Annual Reporting. • All EEC staff have access to shared folders containing the models			
6.	**Approval Process for Research Studies** From the resource allocation perspective, all expenditures (i.e. programs or research studies) are competing against the same pool of finite EEC resources. Therefore, the same level of rigor should be exercised in approving both types of expenditures given significant costs generally associated with such types of expenditures. Currently, the EEC program approval process requires that a business case be submitted and approved prior to the commencement of a new EEC program. However, there is no standard process for the approval of research studies and the evaluation process does not appear to require the same level of rigor.	Inconsistent approval process for EEC programs and research studies can result in ineffective use of EEC resources.	It is recommended that uniform approval processes are applied to both EEC programs and research studies.	Each research study over $10K is now required to have its own business case before proceeding. **Management Accountability:** Sarah Smith, Manager, EEC David Bennett, Director, Resource Planning & Market Development Doug Stout, VP, Marketing & Business Development **Estimated Timing:** Mar 2, 2010
7.	**Program Status Reporting** It was noted that currently there is no regular reporting to management (i.e. Utility Operating Committee (UOC)) on the EEC program including program development and financial information. While the ELT and Board of Directors is informed on a quarterly basis, it is management that is responsible for administrating and managing the program. Also, until program managers implement regular tracking of program information, there is no regular status reporting to Manager of EEC.	Regular monitoring and tracking of program performance can help with more effective use of the EEC resources and assist to achieve program objectives.	It is recommended that regular updates of program progress are reported to the appropriate level of management and personnel for timely monitoring of the programs.	The first regular quarterly report to UOC on EEC activity is scheduled for April 2010 and then subsequent quarters thereafter. The implementation of the Demand Side Management System (DSMS), which will be used to manage various aspects of EEC program administration and performance measurement, will provide regular status reporting to the Manager, EEC. **Management Accountability:** Sarah Smith, Manager, EEC Beth Ringdahl, EEC Program Manager (Residential)

Observations and Recommendations

#	Observations	Risk	Recommendations	Management Response
				Ramsay Cook, EEC Program Manager (Commercial) Ned Georgy, EEC Program Manager (Affordable Housing) Jenny Chia, EEC Program Manager (Community Education & Outreach) Gary Lengle, EEC Program Manager (Enabling & Trades Relations) **Estimated Timing:** April 2010 for reporting to UOC Q4 2010 for implementation of DSMS and regular status reporting to the Manager, EEC

Appendix I

HABART & ASSOCIATES CONSULTING INC.
CONDENSING DOMESTIC HOT WATER HEATERS MARKET TRANSFORMATION

Condensing DHW

Prepared for: Terasen Gas

Prepared by:

abart & Associates Consulting Inc.

March 22 2010

Table of Contents

1. Introduction

1.1 Background

The British Columbia Provincial Government introduced the Energy Plan in 2007 and the BC Climate Action Plan in 2008. The Action Plan set the objective of reducing green house gas emissions by 33% by 2020. Major activities to date have focused on the appliances and the building shell of buildings. Hot water represents the second largest household energy usage (approximately 20% of the total). However this share will increase over time as building envelope construction, space heating appliances and HVAC improve in efficiency.

This has led the Ministry of Energy, Mines and Petroleum Resources (MEMPR) to establish a plan to significantly raise minimum efficiency levels over the next five years. As a result, MEMPR has passed a regulation to increase efficiency levels of residential storage water heaters through a series of steps.

On September 1, 2010, the standard for a 40 USG tank will increase to EF 0.62.

For 2011, the requirement for replacement tanks will increase to EF 0.67 while the requirement for new construction will increase to EF 0.80 for storage water heaters.

For 2013, the requirement will move to EF 0.80 for both new construction and the replacement market.

In the USA the Department of Energy (DOE) sets performance standards for a range of appliances, including Domestic Water Heaters (DWH). The current minimum efficiency level is EF 0.59 which has been in place since 2004. The DOE has now proposed setting the minimum level at EF 0.63 in 2015.

In addition to the minimum energy efficiencies, the ENERGY STAR program defines higher performance levels for water heaters. Prior to August 31, 2010, the standard for a conventional storage water tank is EF 0.62. As of September 1, 2010, this standard will increase to EF 0.67[1]. In addition to the standards for conventional water heaters, ENERGY STAR defines a standard of EF 0.82 for tankless water heaters, and an EF of 0.80 for Condensing water tanks.

At the present time, there are no condensing water tanks specifically for the residential market. Some manufacturers, such as Polaris, do make condensing tanks for Commercial use, but the cost is considered to be too high for widespread residential usage.

Condensing water heaters targeted at the residential sector are expected to be available by mid-2010.

[1] Conversation with DOE staff suggest that this implementation data may be delayed.

1.2 Report Objectives

The purpose of this project is to outline a strategy by which Terasen Gas can support the commercialization of residential condensing water heaters in conjunction with the Ministry of Energy, Mines and Petroleum Resources (MEMPR) of the B C Government.

The paper provides: a conceptual framework for transforming the market; technical information on condensing water heaters; and background on the expected size of the DWH market in B.C.. Then an implementation plan and a business case are provided.

2. Market Transformation

The concept of market transformation gained popularity during the late 1990's in part to respond to a concern that many Demand Side Management programs were dependent on subsidies in order to move more efficient products into the marketplace. The broad thrust of market transformation was to find ways to take advantage of the "natural working" of the market in order to move efficient products from relatively low volume, speciality products into the mainstream so that they displaced the less efficient products. Much of the activity (thought) focused on understanding the barriers that prevent these products from obtaining larger market shares.

2.1 Diffusion theory

The way in which new ideas and technologies are adopted by a society is covered under the broad title of "Diffusion of Innovation" theory. Everett Rogers[2] built on existing thought and wrote the most commonly referenced work on the topic. Briefly, he espoused the concept that, on an individual basis, innovation occurs in a 5 stage process. This includes: awareness; persuasion; decision; implementation; and confirmation.

At the awareness stage, the individual is first exposed to the innovation. In the persuasion stage the individual becomes interested and obtains more information, which leads to the decision point. Once the decision is made (assuming the innovation is not rejected), the implementation stage begins when the innovation is used and experience gained. At the confirmation stage the individual decides either to continue using the innovation or to discard it.

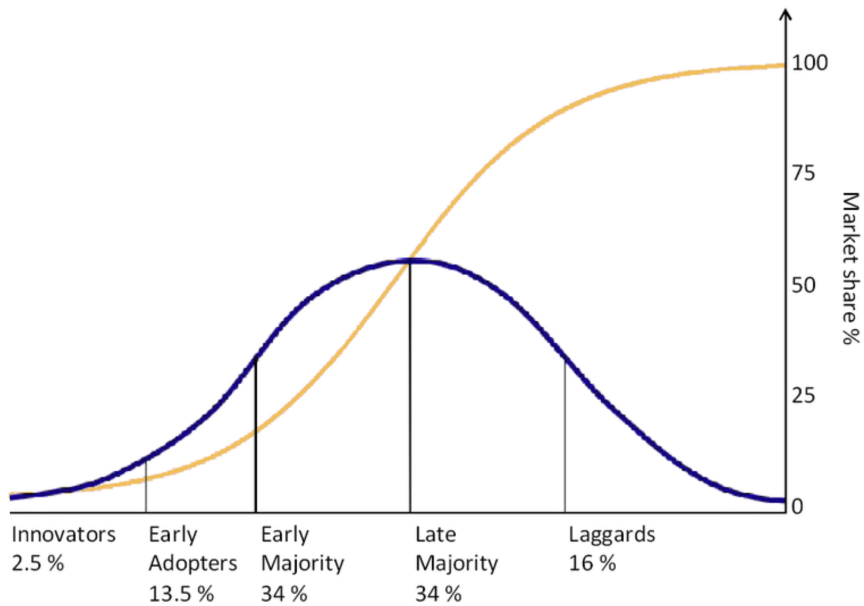
Not all individuals will adopt innovations at the same rate. Rogers defined five categories of individuals based on their tendency to adopt new products. These categories include:

- Innovators. These are the first people to adopt a new product – the first person on the block with the HD TV and Blue Ray disk player. They are willing to take risks, tend to be younger with reasonable incomes.
- Early adopters. These are the second category to adopt new products. They tend to be opinion leaders and again tend to be younger, well educated, have a high social status and reasonable incomes.
- Early majority. These people have a longer time of adoption, and are less of risk takers. Products need to be mature and well proven before this group will adopt them.
- Late majority. These people tend to adopt after the majority of society. They approach new products with a high degree of scepticism. They also tend to have lower social status, less financial flexibility and are followers rather than opinion leaders.
- Laggards. These are the last group to adopt technologies. They tend to be older and high a high resistance to change.

[2] Rogers, E. (1962) *Diffusion of innovations*. Free Press, London, NY, USA

Exhibit 1 shows the approximate size of these five groups. The exhibit also shows the “S” curve of adoption of new technology. The shape of the curve is driven by the relative speed with which each of the five segments adopt new technology.

Exhibit 1: Product Diffusion Curve



The product diffusion curve also provides some insights about the types of marketing program activities that are appropriate at each stage of adoption.

When introducing a new product, the market is primarily the innovators and early adopters. These people need to become aware of the technology, and require good information to help them evaluate and make the decision. Appropriate utility activities include demonstration projects to build experience with the product and to develop credible data on its performance. Utilities also have a strong role to play in raising awareness of the product, especially as they are often considered a more credible source of information than the vendors.

At the early majority stage, incentives are added as a key element to speed the adoption of the technology. The incentives serve to improve the economics of the decision, but they also are a very powerful way to raise awareness of the product, and provide credibility (if the utility is willing to help fund this product, it must perform).

At the late majority, labelling (including “premium labels” such as ENERGY STAR) are important as well as ongoing marketing and public education.

Finally, the laggards are not likely to make decisions to adopt the new technology on their own. Codes and Standards become the most effective tool as they take the older technologies off the market.

2.2 Market Barriers

Diffusion theory provides the "big picture" of the process to transform the market for a specific product, and it also provides general guidance of the types of utility activities that are appropriate at each stage of transformation.

The second conceptual model more specifically addresses market barriers, and again is useful to help in development of utility DSM programs. This approach is referred to as the "Five A's", and has been used by Natural Resources Canada and B.C. Hydro to aid in the development of program strategies and tactics.[3] The Five As are:

Availability. Is the product or technology readily available on the market? This includes not only the availability of the physical product, but also information such as performance, reliability and etc. This should consist of more than just manufacturers information, and includes third party evaluations and case studies, test standards and etc. The utility can play a key role by undertaking demonstration and pilot projects, and providing a third party case study to document the performance of the product under actual conditions.

Awareness. Is the market aware of the product? The market includes both the end users of the technology and the distribution channels. Awareness includes the benefits and costs of the product, Again the utility can play a strong role in the introduction of a new product by providing training for the distribution channels, sales aids such as POP materials, and advertising and promotion to the end user.

Accessibility. Is the product easily accessible to the customer? In the retail distribution channel, is the product and its benefits prominently displayed, and is the product available throughout the province. In the case of the plumber distribution channel, is the product stocked by the plumber and "on the truck". A large component of the replacement market occurs on product failure, and speed of replacement is paramount. For new construction, is the product available in sufficient quantity, and are there sufficient trained trades to install the product.

Affordability. Is the product affordable? Affordability includes not only the payback to the customer, but also the incremental cost, as many customers are "cash strapped" and will choose the lowest cost product regardless of the expected payback on the additional expense.

Acceptability. Does the product meet the needs of both the end user and the distribution channels? For the customer, this includes not only achieving the expected energy savings, but also the performance and reliability of the product. For the distribution channels, acceptability includes meeting the profitability expectations, and well as the ease of installation and a reasonable level of "call-backs" to resolve customer issues.

[3] To the best of the author's knowledge, this framework was developed by the US consulting firm A.D. Little.

2.3 Regulations

Regulations are an important tool in Market Transformation. They are likely the only tool to address the “laggards”, but if regulations can be introduced into the product diffusion process earlier, they can significantly speed the transformation.

In British Columbia, the legislative framework for regulating appliance and water heater efficiency already exists. What is required is the development of new regulations to increase the minimum efficiency level of the product. The Ministry of Energy, Mines and Petroleum Resources (MEMPR) takes the lead and typically forms a Technical Advisory Group (TAG) to assist it in the development of the regulations. The TAG will typically include: representatives of the manufacturers, representatives of the distribution channels and relevant trades, and the affected utilities'.

As this is a consensus process, it is necessary to have all major parties agree with the regulations before MEMPR will move forward. Typically the following conditions must be met before new regulations can be considered:

- All major manufacturers can provide the product;
- The major distributors carry the product;
- All distribution channels have experience delivering the product;
- The necessary trades have experience with the product, and support its sale;
- The product performs to the appropriate level, including providing the expected energy reductions, service levels and reliability; and
- There is a valid benefit for customers.

3. Condensing Water Heaters

3.1 Description

A condensing water heater is similar to a standard efficiency gas storage water heater but has an improved heat exchanger that allows the latent heat to be extracted from the flue gas and provides a thermal “steady state” efficiency of up to 96%. However, as these are storage water tanks, and when stand-by losses, and possible flue losses are included, the effective EF will be lower. As residential condensing water heater products are not yet available on the market, there are no measured EF ratings available. For the purpose of this document, it is assumed that the effective ratings will be EF 0.80, which is the current ENERGY STAR standard for condensing water tanks.

There are condensing water tanks available for Commercial use. They appear to function well, but are relatively expensive for residential usage.

3.2 Benefit / Cost

For the purpose of this study, it has been assumed that the incremental cost to move from a conventional DWH storage tank to a condensing unit will be about $1,750. However it is anticipated that the incremental cost of the condensing tank will decrease as these tanks becomes predominant in the marketplace.

Assuming the baseline water heater has an EF of 0.57, the condensing tank is assumed to reduce natural gas consumption by 7 GJ[4] per year.

At the projected incremental cost this product is not cost effective to the customer. The B / C ratio is about 0.33. Without a decrease in the incremental cost, this technology does not provide a payback for the customer.

However, it is reasonable to expect the incremental cost to decrease. When a new, efficient product appears on the market, it is typically priced as a premium product. There are a number of costs associated with new products that must be recovered. These include:

- R&D and design costs;
- New tooling costs, especially for the heat exchangers;
- More, and more expensive materials for the tank / heat exchanger;
- Lack of manufacturing economies of scale due to low volumes; and
- Lack of distribution channel economies of scale.

As the product moves into volume production, costs tend to drop as the development costs are recovered or amortized over a larger volume of sales. Incremental material costs may remain, but often these will also decrease as product designs are refined with experience. Finally, the manufacturing and distribution costs will drop with volume production.

[4] The savings have been estimated using HOT2000. The archetype is for an EGH80 natural gas heated dwelling.

There is no data available on how the incremental costs might drop over time for the condensing water tanks. However, if we look at the furnace market, some analogies may be possible. At the time mid efficiency furnaces were last sold in B.C., the incremental cost to move from a mid efficiency furnace to a high efficiency furnace was approximately $600. The differences between a mid efficiency furnace and a high efficiency furnace appear to be more complex than for a condensing water heater. For the purpose of this study, it is assumed that the incremental cost will decrease from the current $1,750 to $500. For the business case analysis, it is assumed that the incremental cost declines at a rate of 10% per year until it reaches $500 and then remains constant for the balance of the analysis.

4. DWH Market

There are two major components to the market place for condensing water heaters, the new construction market and the replacement market.

4.1 New Construction Market

The market model for the new construction market is summarized in Exhibit 4.1 below. It is predicated on the assumption than an average level of new construction starts will be about 22,800 per year across B.C. This is the average number of completions per year from 2000 to 2008 as reported by CMHC. The share of starts by detachment is based on the actual shares of completions in 2008. The penetration of natural gas water heaters is based on research undertaken by the author on shares in New Construction. It is assumed that there are no natural gas DWH in the apartment sector. While this is not strictly correct as there may be some in Vertical Subdivisions, the number is small and will not affect the analysis. There was no data on new mobile home installations, and this market has not been included.

Exhibit 4.1: Domestic Water Heater Market – New Construction

Forecast Starts	Detachment	Detachment Shares	Detachment Number	N. G DWH Shares	Est. DWH Sales
22,800	SFD	29%	6,612	83%	5,488
	Duplex	5%	1,140	14%	160
	RH	11%	2,508	1%	25
	Apartment	55%	na	na	na
	Total				5,673

4.2 Replacement Market

The size of the replacement market was estimated by using a capital stock turnover model. A capital stock turnover model works by estimating the population of water heaters in existing customers, and then using the average life of a water heater to estimate how many water heaters are expected to fail each year. A separate estimate was made for TGI and TGVI as the shares of natural gas water heater are different between the two companies. Exhibit 4.2 shows the data used to estimate the eligible population.

Exhibit 4.1: Domestic Water Heater Market – Replacement

Customer Base		TGI		TGVI		Popul-ation
		Det. Shr.	DWH Shr.	Det. Shr.	DWH Shr.	
TGI - 755,660 TGVI - 88,321	SFD	83.7%	90.6%	83.8%	83.0%	634,464
	Duplex	4.8%	89.9%	6.0%	83.8%	37,049
	RH	8.1%	86.2%	6.8%	6.0%	53,122
	Apartment	0.7%	66.9%	1.2%	6.8%	3,661
	Mobile	2.1%	47.0%	2.2%	5.0%	7,556
	Total					735,002

Based on a expected life of 13 years, then about 7% will be replaced each year. The replacement market is expected to be about 49,242 units per year. In total the market is estimated at approximately 55,000 water heaters per year.

5. Implementation Plan

Section 2 of this report outlined the basic concepts of Market Transformation. This section develops a plan to move Condensing Water Heaters from initial introduction through to regulation.

5.1 Pilot / Demonstration Projects and Market Preparation

As condensing residential water heaters are a new product, the first step is to determine and demonstrate the performance of the product in actual use, rather than in laboratory testing conditions. Issues of concern include: installation procedures; energy savings performance; and product reliability.

The approach suggested in this study is to develop 20 test installations. These installations should include metering and recording the natural gas usage for the existing water heater before the condensing tank is installed, and then further metering with the new tank to establish the change in consumption. If the test metering is done for a short period of time, it may also be necessary to meter the hot water usage before and after the tank change. It may be desirable to have a different plumbing firm do each installation so that a range of installation experience can be collected.

Once the pilot demonstration projects are under way, case study materials should be developed. One set of materials should be sales tools that can be used by both plumbers and retail to provide valid information on the performance of the product. Another set should cover off any installation issues to guide plumbers as they install the new technology tanks.

Finally training should be developed for the plumbing community and for retailers. For the plumbing community this may take the form of seminars (often breakfast meetings) to raise awareness, discuss installation, and provide a forum for questions and answers to understand the issues in the trade’s minds about these products. The business case assumes a small “spiff” for sales of these tanks, and this will help to increase enthusiasm.

Training will also be required for the retail distribution channel. This can often be arranged by first getting support from the head offices, and then conducting some training in the stores. It is common for retailers to hold staff meetings before the store opens, and for utility staff to provide updates as part of these meetings. A determination will have to be made if spiff’s will be offered to the retail chain. The key element of using the spiffs is likely to be the existence of dedicated sales staff who are on commission.

In parallel with the development of these pilot / demonstration projects, utility staff should be working with the water tank manufacturers, the major distributors and major plumbing companies to ensure that the product will move smoothly through their organizations. The expectation of promotional advertising and customer rebates provide a strong incentive for these businesses to work with the utility.

The focus of these activities is to prepare the ground for the Innovators and Early Adopters. They address the barriers of: availability and especially the knowledge aspects of availability; awareness in the distribution channels; and accessibility in the distribution channels.

5.2 Product Marketing

Once the basic performance data for the products has been ascertained and the distribution channels have been primed, the next step is to accelerate the marketing of the product. The business case assumes a three pronged approach for the replacement market: advertising likely including bill inserts, home shows, possible mall displays as well as media advertising; sales "spiffs" to encourage sales staff to promote the product and encourage plumbers to have condensing tanks "on the truck" so that they can sell and provide the product when responding to tank failures; and customer incentives to both raise awareness of the product; and to provide a positive benefit / cost ratio to the consumer.

A separate set of initiatives will be required for the new construction market, which is likely much more "first cost" oriented than the replacement market. For the business case, it is assumed that the utility will be operating a new construction program, and the condensing water heaters will be included in that program.

These actions will address the barriers of accessibility awareness and affordability. It is also expected that the market development activities outlined here will ensure that the major water tank manufacturers will have product, that the distribution channels will stock the product, that the trades will know how to sell and install the product, and that customers are both aware of the product and have sufficient valid information to make the decision to adopt it.

5.3 Program Timing

The current schedule from MEMPR envisions regulations for Condensing Water heaters by 2013. This is a very aggressive time-table as condensing residential hot water tanks are not yet available on the market. This study assumes a longer implementation period will be required for two basic reasons:

1. For a product to be regulated, it will require a performance and reliability track record; and
2. With an expected incremental cost of $1,750 and a 10% annual price decrease, the product will not provide a positive payback to the consumer until about 2016.

For these reasons, a 7 year program is used to move the product to Market Transformation.

Following is the schedule anticipated in this study.

Year 1: Program development and twenty pilot / demonstration projects. There is a requirement for some time to perform both "pre" and "post" metering of the tanks and to develop the necessary support material. Support material includes: case studies; installation instructions; and trade training. During this year it will also be necessary to start work with the manufacturers and distribution channels to ensure that product is available.

Year 2: This is the launch and execution of the marketing program, and on-going relations with the manufacturers and distribution channels to resolve any problems. It is assumed that about 300 tanks will be installed during the first year.

Year 3 - 7: This is the continuation of the marketing program. The assumptions are that sales will be ramp up from about 750 to 12,000 in year 7. A volume of 12,000 per year represents about 20% of the total DWH market in BC. It is thought that a 20% market share, whiles still quite low, will be adequate when supporting MEMPR regulations. This level of sales should ensure that the manufacturers and distributors have experience with, and have accepted the product.

It should be noted that, based on the initial cost estimate and the 10% per annum cost reduction, the product will not provide a benefit to the customer until year 8, the year that regulations are assumed to come into force. Prior to this year, the utility incentive is required to make the product financially viable to the customer.

Year 8: It is assumed that the MEMPR regulations come into effect at this year, and that all program activities will cease.

6. Business Case

The business case detail analysis is included in a separate spreadsheet in Appendix 1.

Exhibit 6.1 summarizes the sales ramp up for the condensing water heaters, and summarizes the associated costs. The total cost of the program over the 7 years is $26.1 million. The program is based on an incentive of $1,000 to the customer for each unit sold, and an additional incentive of $50 to the sales person (retail or plumber).

Exhibit 6.1: Program Sales and Costs ($ in'000)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Sales (units)	10	300	750	1,500	3,000	6,000	12,000
Pgm Dev /Pilot ($)	150						
Train / Retail ($)		25	25	25	25	25	25
Advertising ($)		100	100	100	100	100	100
Incentive admin ($)		6	15	30	60	120	240
Incentive ($)		315	788	1,575	3,150	6,300	12,600
Total ($)	150	446	928	1,730	3,335	6,545	12,965

Exhibit 6.2 summarizes the Benefit / Cost tests associated with the 13 years of the program (7 years of program activity and 6 years of "credit" for the market transformation). With 6 years credit, the program achieves a Total Resource Cost benefit / cost ratio of just over 1. The Utility Cost is strong a 6.8 while the RIM is reasonable for a residential program of 0.71.

Exhibit 6.2: Program B / C

	Benefit / Cost
TRC	1.01
UTC	6.77
RIM	0.71

By way of comparison, Exhibit 6.3 shows the benefit / cost tests if no credit was given for additional savings, and also shows the impact of a 20 year analysis of costs and benefits. The second column shows that, if no credit is provided, or if regulation is not achieved and condensing water heater sales drop, the program fails on all tests. The third column shows the impact of the program over a 20 year period, and shows the foregone benefit from the perspective of condensing water heaters (or an equivalent technology) not taking over during the 20 year period without a program.

Exhibit 6.3: Program B / C

	Benefit / Cost (no credit)	Benefit / Cost (20 yr)
TRC	0.59	1.22
UTC	0.55	12.01
RIM	0.32	0.76

6.1 Critical Assumptions / Success Factors:

Following are the critical assumptions necessary for the success of this program.

- Incremental cost of Condensing Water Heaters decreases. At the projected incremental cost, the product is not cost effective to the end user. The study assumes a 10% per annum cost reduction from the manufacturers / distributors. If this does not materialize, the probability of the program failing the overall benefit cost test increases.
- The business case assumes that the utility can take sole credit for moving regulations forward by 6 years. This was the minimum period that would provide a TRC of greater than 1.0 for the program. This period of credit would seem reasonable when compared instantaneous water heaters. They have been available for at least 20 years, and have major market shares in some European countries. However these products are only now gaining traction in the B.C. market. Moving a new product from commercializing to regulation over a period of 7 years would not be possible without strong support from the utility.

6.2 Business Case Summary

The business case assumes a seven year program by the utility which includes both incentives and marketing. The total cost of the program over 7 years is $26.1 million with a net present value of these costs of approximately $18.25 million. The savings in natural gas over the 13 years of analysis (for which the utility would receive credit) is 32 million GJ of natural gas. The net present value of these savings is $124 million while the net present value of the costs, including both customer costs and utility costs) is $122 million. The TRC Benefit Cost ratio of the program to society is 1.01.

The program will not be cost effective unless the utility receives credit for savings after the regulations are passed. This analysis shows that the TRC would be only 0.59 and the Benefit / Cost to the utility would be 0.55.

7. Summary

This paper outlines a strategy to move a new technology, condensing residential water heaters, from product introduction to regulation.

The strategy includes a preliminary year of pilot projects to obtain actual field experience with the technology, including installation experience, product performance, and energy savings. Data from these pilot projects will be used to develop customer, marketing and trades training materials. The second year will include a full program launch with customer and trade incentives and strong advertising and awareness promotion. It is thought that after 6 years of marketing promotion and incentives, condensing water heaters will have about a 20% market share which will be sufficient to support MEMPR developed regulations to remove less efficient products from the market.

This program will not be cost effective unless Terasen Gas is provided with credit for load reduction that occurs after the water heater regulations come into effect. The business case shows that, without this credit, the TRC is only 0.59, and the Utility Cost benefit is 0.55. This is not a viable investment for Terasen Gas's DSM program.

Further analysis determined that Terasen Gas would need to receive credit for an additional 6 years of savings. This additional savings results in a TRC of 1.01 and a UTC of 6.77, which makes the program viable from the perspective of both the utility and society.

Providing 6 years of post regulation credit for the program appears reasonable. This essentially assumes that, without the support of this marketing program, MEMPR would not be able to pass regulations until some date after year 13. Considering the example of instantaneous water heaters. They have been available for over 20 years, but are just now starting to gain traction in the marketplace. There is no reason to think that condensing water heaters will gain market share any faster without strong utility support.

The total cost of this program to Terasen Gas is estimated at $26.1 million, and it is expected to reduce natural gas requirements by 32 TJ over the 13 year life of this analysis.

The two critical success factors for this program are:

- the incremental cost of the Condensing water heater decreases as forecast in the business case: and
- the utility obtains credit for savings that occur after the enactment of regulations by MEMPR .

8. Appendix 1

Water Heater Market Transformation Strategy - Feb 23 2009

Market Transformation Model

Assumptions

DWH Market		
	Number	Share
New	5,673	10.3%
Replace	49,242	89.7%
Total	54,915	
Technology		
EF	0.8	
Incr. Cost	$2,000	
Ener. Red.	7	GJ
Life	13	yr.
Program		
Activity	Number	Cost
Pgm Dev.	1	$40,000
Demo	20	$5,000
Case Study	20	$500
Training*	5	$5,000
Cont. Mail	Annual	$20,000
Spif	Sales	$50
Incentive	Sales	$1,000
Admin	Sales	$20
Adv.	Annual	$100,000
* Includes retail support		
Regulation eff. date		
2017		
Technology Cost		
Price Red.	10%	/yr
Financial		
TGI	7.38%	
Inflation	0.00%	
Disc. rate	7.38%	
Tariff	$12	
Incr. (real)	0.50%	

Scenario 2 - 7 year program

Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Year		1	2	3	4	5	6	7	8	9	10	11
Unit Cost		$1,750	1,575	1,418	1,276	1,148	1,033	930	837	753	678	610
Tariff (Arvind)		$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80
Tariff (Jack)		$10.99	$11.75	$12.18	$12.63	$13.14	$13.43	$13.67	$13.90	$14.14	$14.38	$14.62
Avoided Cost		$ 7.85	$ 8.61	$ 9.04	$ 9.49	$ 10.00	$ 10.30	$ 10.53	$ 10.76	$ 11.00	$ 11.24	$ 11.48
NPV (Tariff-Arvind)		$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19
NPV (Tariff-Jack)		$751.67	$772.83	$790.95	$808.16	$824.25	$838.73	$852.89	$867.28	$881.90	$896.75	$911.91
NPV (Avoided cost)		$571.95	$593.11	$611.23	$628.44	$644.53	$659.00	$673.17	$687.56	$702.18	$717.03	$732.19
Sales		10	300	750	1,500	3,000	6,000	12,000	54,915	54,915	54,915	54,915
Terasen Program (2022)												
Total Avoid Gas (NPV)	$123,533,042	$5,719	$177,932	$458,423	$942,657	$1,933,595	$3,954,028	$8,078,032	$37,757,056	$38,559,885	$39,375,270	$40,208,095
Total Lost Rev - A(NPV)	$96,788,865	$5,612	$168,356	$420,890	$841,780	$1,683,561	$3,367,121	$6,734,242	$30,817,441	$30,817,441	$30,817,441	$30,817,441
Total Lost Rev - J(NPV)	$154,530,118	$7,517	$231,848	$593,215	$1,212,241	$2,472,763	$5,032,364	$10,234,704	$47,626,482	$48,429,312	$49,244,697	$50,077,521
Total Equip Costs (NPV	$121,051,096	$17,500	$472,500	$1,063,125	$1,913,625	$3,444,525	$6,200,145	$11,160,261	$45,964,729	$41,368,256	$37,231,431	$33,508,288
	20 Year Perspective		**7 year Perspective**									
Total Avoid Gas (NPV)	$219,138,883		$10,079,894			32,127,419						
Total Lost Rev - A(NPV)	$161,740,678		$8,590,979									
Total Lost Rev - J(NPV)	$270,937,074		$12,831,195									
Total Costs (NPV)	$178,921,138		$15,960,986									
Program Costs												
Program Dev.		$40,000										
Demo / case stdy		$110,000										
Training / Retail			$25,000	$25,000	$25,000	$25,000	$25,000	$25,000				
Advertising			$100,000	$100,000	$100,000	$100,000	$100,000	$100,000				
Administration			$6,000	$15,000	$30,000	$60,000	$120,000	$240,000				
Program Costs (NPV)	$994,095	$150,000	$131,000	$140,000	$155,000	$185,000	$245,000	$365,000				
NPV (Pgm w/out inc)												
Incentives / Spif (NPV)	$17,249,781		$315,000	$787,500	$1,575,000	$3,150,000	$6,300,000	$12,600,000				
	7 yr (no MT credit)	**13 year (T.Gas Pgm)**	**20 Year (Society)**									
TRC (T. Gas Program)	**0.59**	**1.01**	**1.22**									
UTC	**0.55**	**6.77**	**12.01**									
RIM	**0.38**	**1.07**	**1.22**									
RIM (alternative)	**0.32**	**0.71**	**0.76**									

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
549	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80	$9.80
$14.86	$15.11	$15.36	$15.62	$15.89	$16.16	$16.44	$16.69	$16.98	$17.28	$17.58	$17.89	$18.20	$18.53	$18.86	$19.19	$19.54	$19.89
$ 11.72	$ 11.97	$ 12.22	$ 12.48	$ 12.75	$ 13.02	$ 13.30	$ 13.55	$ 13.84	$ 14.14	$ 14.44	$ 14.75	$ 15.07	$ 15.39	$ 15.72	$ 16.06	$ 16.40	$ 16.75
$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19	$561.19								
$927.40	$943.22	$959.38	$975.89	$992.74	$1,009.96	$1,027.54	$1,045.50	$1,063.84	$1,081.51								
$747.68	$763.50	$779.66	$796.16	$813.02	$830.24	$847.82	$865.78	$884.12	$901.78								
54,915	54,915	54,915	54,915	54,915	54,915	54,915	54,915	54,915	54,915								
$41,058,725	$41,927,534	$42,814,900	$43,721,210	$44,646,855	$45,592,236	$46,557,756	$47,543,828	$48,551,000	$49,521,263								
$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441	$30,817,441								
$50,928,152	$51,796,960	$52,684,327	$53,590,636	$54,516,282	$55,461,662	$56,427,182	$57,413,255	$58,420,427	$59,390,689								
$30,157,459	$27,457,380	$27,457,380	$27,457,380	$27,457,380	$27,457,380	$27,457,380	$27,457,380	$27,457,380	$27,457,380								

Appendix J

COST BENEFIT ANALYSIS

2009 DSM Actuals

	PROGRAM									ALTERNATE		NET									Benefits/co						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings					Participant				
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2009 Actuals																											
Residential Energy Efficiency Programs:																											
Retrofit																											
Energy Efficiency	2,022	166	2,189	2,803	4,991	44%	56%	94,494	55,031	0	-	4	5,895	0	5,887	837	0	574,607	-	-	2.7	2,803	6,723	2.4	0.7	1.2	904
2009 Residential Total	**2,022**	**166**	**2,189**	**2,803**	**4,991**	**44%**	**56%**	**94,494**	**55,031**	**0**	-	**4**	**5,895**	**0**	**5,887**	**837**	**0**	**574,607**	-	-	2.7	2,803	6,723	2.4	0.7	1.2	904
Commercial Energy Efficiency Programs:																											
New Construction	13	2	15	37	52	28%	72%	1,088	892	0	-	1	103	0	163	14	0	9,869	-	-	7.1	37	177	4.8	0.6	2.0	52
Retrofit	912	145	1,057	2,433	3,491	30%	70%	88,181	73,481	0	-	2	7,202	0	6,683	953	0	683,482	-	-	6.8	2,433	7,636	3.1	0.9	2.1	3,712
2009 Total Commercial	**925**	**147**	**1,072**	**2,471**	**3,542**	**30%**	**70%**	**89,269**	**74,373**	**0**	-	**2**	**7,305**	**0**	**6,845**	**967**	**0**	**693,352**	-	-	**6.8**	**2,471**	**7,812**	**3.2**	**0.9**	**2.1**	**3,763**
Conservation for Affordable Housing Programs																											
Retrofit Total	**390**	**0**	**390**	**229**	**620**	**63%**	**37%**	**1,352**	**1,352**	**138**	**0**	**16**	**189**	**233**	**143**	**21**	**123**	**14,236**	**1,492**	**0**	**0.6**	**229**	**288**	**1.3**	**0**	**0.7**	**-197**
Joint Initiatives																											
2009 Joint Initiatives	**7**	**0**	**7**	**19**	**25**	26%	74%	**368**	**210**	**0**	**0**	**3**	**19**	**0**	**19**	**3**	**0**	**1,905**	**0**	**0**	**2.9**	**19**	**22**	**1.2**	**1**	**0.8**	**-6.18720404**
SUBTOTALS:																											
Program	**3,344**	**313**	**3,657**	**5,521**	**9,179**	**40%**	**60%**	**185,483**	**130,965**	**138**	**0**	**2.8**	**13,408**	**233**	**12,894**	**1,827**	**123**	**1,284,100**	**1,492**	**0**	**3.7**	**5,521**	**14,845**	**2.7**	**0.8**	**1.5**	**4,463**
Portfolio Level Expenditure																											
Conservation Education & Outreach		612																									
Joint Initiatives		428																									
Enabling activites		266																									
DSMS consultant costs		11																									
Research & evaluation		15																									
consultant fees		86																									
Non Program admin		1,186																									
Portfolio level Total		**2,604**																									
2009 TOTAL	**3,344**	**2,917**	**6,261**	**5,521**	**11,782**	**53%**	**47%**	**185,483**	**130,965**	**138**	**0**	**5**	**13,408**	**233**	**12,894**	**1,827**	**123**	**1,284,100**	**1,492**	-	**2.1**	**5,521**	**14,845**	**2.7**	**0.7**	**1.2**	**1,859**

TERASEN GAS INC 2009 DSM Actuals

2009 TGI Programs Actuals	PROGRAM COSTS ($000) Utility Incentives	PROGRAM COSTS ($000) Utility Administration	PROGRAM COSTS ($000) Utility Total	PROGRAM COSTS ($000) Participant	PROGRAM COSTS ($000) Total	PROGRAM COSTS ($000) % Utility	PROGRAM COSTS ($000) % Participant	PROGRAM SAVINGS (GJ) Gross	PROGRAM SAVINGS (GJ) Net	ALTERNATE Impact Energy MWh	ALTERNATE Impact Capacity kW	Levelized Cost ($/GJ)	NET PRESENT VALUE Utility Benefits (Costs) Program ($'000s)	NET PRESENT VALUE Utility Benefits (Costs) Alternate ($'000s)	NET PRESENT VALUE Participant Benefits (Costs) Program ($'000s)	NET PRESENT VALUE Participant Benefits (Costs) Carbon Tax ($'000s)	NET PRESENT VALUE Participant Benefits (Costs) Alternate ($'000s)	NET PRESENT VALUE Program Net Savings Natural Gas (GJ)	NET PRESENT VALUE Program Net Savings Alternate Energy (MWh)	NET PRESENT VALUE Program Net Savings Alternate Capacity (kW)	Benefit/cost test Natural Gas Utility	Benefit/cost test Participant Total Costs ($'000s)	Benefit/cost test Participant Total Benefits ($'000s)	Benefit/cost test Participant Benefit/Cost	Benefit/cost test Natural Gas Rate Impact	Benefit/cost test Total Resource	Benefit/cost test TRC Net Benefits ($'000s)
2009																											
Residential Energy Efficiency Programs:																											
Retrofit																											
Energy Efficiency	1,975	138	2,113	2,729	4,842	44%	56%	91,279	52,901	0	-	4	5,682	0	5,575	806	0	553,543	-	-	2.7	2,729	6,381	2.3	0.7	1.2	840
Subtotals																											
Residential Energy Efficiency	1,975	138	2,113	2,729	4,842	44%	56%	91,279	52,901	0	-	4	5,682	-	5,575	806	-	553,543	-	-	3	2,729	6,381	2.3	0.7	1.2	840
2008 Residential Total	**1,975**	**138**	**2,113**	**2,729**	**4,842**	44%	56%	91,279	52,901	**0**	-	**4**	**5,682**	-	**5,575**	**806**	-	**553,543**	-	-							
Commercial Energy Efficiency Programs:																											
Retrofit																											
Energy Efficiency	874	140	1,014	2,322	3,336	30%	70%	84,917	70,804	0	-	2	6,893	0	6,195	911	0	653,874	-	-	6.8	2,322	7,105	3.1	1.0	2.1	3,557
2008 Total Commercial	**874**	**140**	**1,014**	**2,322**	**3,336**	**30%**	**70%**	**84,917**	**70,804**	**0**	-	**2**	**6,893**	**0**	**6,195**	**911**	**0**	**653,874**	**0**	-	**6.8**	**2,322.3**	**7,105.2**	**3.1**	**1.0**	**2.1**	**3,557**
Joint Initiatives																											
2009 Joint Initiatives	**7**	**0**	**7**	**19**	**25**	26%	74%	**368**	**210**	**0**	**0**	**3**	**19**	**0**	**19**	**3**	**0**	**1,905**	**0**	**0**	**2.9**	**19**	**22**	**1.2**	**1**	**0.8**	**-6**
Conservation for Affordable Housing Programs *																											
Retrofit	390	0	390	229	620	63%	37%	1,352	1,352	138	0	16	189	233	143	21	123	14,236	1,492	0	0.6	229.4	288	1.3	0.4	0.7	-197
Portfolio level expenditure																											
Conservation Education & Outreach		530																									
Joint Initiatives		405																									
Enabling activites		59																									
DSMS consultant costs		9																									
Research & evaluation		12																									
consultant fees		69																									
Non Program admin		1135																									
TGI Portfolio level total		**2220**																									
2009 Total	**3,245**	**2,498**	**5,743**	**5,299**	**11,042**	**52%**	**48%**	**177,916**	**125,267**	**138**	-	**4.7**	**12,783**	**233**	**11,932**	**1,740**	**123**	**1,223,559**	**1,492**	**0**	**2.2**	**5,299**	**13,796**	**2.6**	**0.7**	**1.2**	**1,973**

	PROGRAM									ALTERNATE		NET									BENEFIT/COS						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
2009 TGVI Programs Actuals	Utility			Participant	Total	% Utility	% Participant	Gross	Net	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total							MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2009																											
Residential Energy Efficiency Programs:																											
Retrofit																											
Energy Efficiency	47	28	75	74	149	51%	49%	3,214	2,130	0	-	4	213	0	311	31	0	21,063	-	-	2.8	74	342	4.6	0.6	1.4	64
Subtotals																											
2009 Residential Total	**47**	**28**	**75**	**74**	**149**	**51%**	**49%**	**3,214**	**2,130**	**0**	**0**	**4**	**213**	**0**	**311**	**31**	**0**	**21,063**	**0**	**0**	**3**	**74**	**342**	**5**	**0.6**	**1.4**	**64**
Commercial Energy Efficiency Programs:																											
New Construction	13	2	15	37	52	28%	72%	1,088	892	-	-	1	103	-	163	14	-	9,869	-	-	7.1	37	177	4.8	0.6	2.0	52
Retrofit	39	5	44	111	155	28%	72%	3,264	2,676	-	-	1	309	-	488	42	-	29,608	-	-	7.1	111	530	4.8	0.6	2.0	155
2008 Total Commercial	**51**	**7**	**58**	**148**	**206**	**28%**	72%	**4,352**	**3,569**	**-**	**-**	**1**	**412**	**-**	**651**	**56**	**-**	**39,478**	**-**	**-**	**7.1**	**148**	**707**	**4.8**	**0.6**	**2.0**	**206**
Portfolio level expenditure																											
Conservation Education & Outreach		81																									
Joint Initiatives		23																									
Enabling activites		207																									
DSMS consultant costs		2																									
Research & evaluation		3																									
consultant fees		17																									
Non Program admin		50																									
TGVI Portfolio level total		**384**																									
2009 Total	**98**	**419**	**518**	**222**	**739**	**70%**	**30%**	**7,566**	**5,698**	**0**	**-**	**9**	**625**	**0**	**962**	**87**	**0**	**60,541**	**-**	**-**	**1.2**	**222**	**1,049**	**4.7**	**0.4**	**0.8**	**(114)**

TERASEN GAS INC

2009 Commercial Energy Efficiency Programs

2009 Commercial Energy Efficiency Programs	PROGRAM – Utility – Incentives	PROGRAM – Utility – Administration	PROGRAM – Utility – Total	PROGRAM – Partners – Incentives	PROGRAM – Partners – Administration	PROGRAM – Partners – Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) – Gross	SAVINGS (GJ) – Net-to-Gross	SAVINGS (GJ) – Net	LIFE – Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2009															
Commercial Energy Efficiency Program															
Retrofit															
Retrofit Efficient Boiler Program	783	101	885	-	-	-	2,260	3,145	28%	-	72%	66,368	82%	54,422	20
Retrofit Light Comm ENERGY STAR® Boiler Program	32	20	52	-	-	-	62	114	46%	-	54%	3,898	82%	3,197	20
Retrofit Energy Assesment Program	59	18	77	-	-	-	0	77	100%	-	0%	14,651	90%	13,186	1
Total Commercial	874	140	1,014	-	-	-	2,322	3,336	30%	-	70%	84,917		70,804	

2009 Commercial Energy Efficiency Programs	ALTERNATE Impact – Energy (MWh)	ALTERNATE Impact – Capacity (kW)	NET Levelized Cost ($/GJ)	BENEFIT/COST – Utility Benefits – Program ($'000s)	Utility Benefits – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	Natural Gas Utility	Participant Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP +	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2009																		
Commercial Energy Efficiency Program																		
Retrofit																		
Retrofit Efficient Boiler Program	-	-	1	6,337	N/A	5,743	860	N/A	605,888	-	-	7.2	2,260	6,603	2.9	1.0	2.0	3,193
Retrofit Light Comm ENERGY STAR® Boiler Program	-	-	1	372	N/A	337	51	N/A	35,589	-	-	7.15346345	62.31918	388	6.2	1.0	3.3	258
Retrofit Energy Assesment Program	-	-	6	183	N/A	114	N/A	N/A	12,396	-	-	2.4	-	114	N/A	1.0	2.4	106
Total Commercial	-	-	2	6,893	0	6,195	911	0	653,874	0	0	6.8	2,322	7,105	3.1	1.0	2.1	3,557

TERASEN GAS VANCOUVER ISLAND

2009 Commercial Energy Efficiency Programs	PROGRAM															ALTERNATE		NET BENEFIT/COST															
	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
	Utility			Partners											Years	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	B	C	D	E	F	G	H	I	J	K	L	Input	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2009																																	
Commercial Energy Efficiency Programs																																	
New Construction																																	
Efficient boiler Program	13	2	15	-	-	-	37	52	28%	-	72%	1,088	1	892	20	-	-	1	103	N/A	163	14.1	N/A	9,869	-	-	7.1	37	177	4.8	0.6	2.0	52
Retrofit																																	
Retrofit Efficienct Boiler Prog	39	5	44	-	-	-	111	155	28%	-	72%	3,264	82%	2,676	20	-	-	1	309	N/A	488	42.3	N/A	29,608	-	-	7.1	111	530	4.8	0.6	2.0	155
Total Commercial	51	7	58	-	-	-	148	206				4,352		3,569		0	-	1	412	0	651	56	0	39,478	-	-	7.1	148	707	4.8	0.6	2.0	206

TERASEN GAS INC

2009 Residential Energy Efficiency Programs	PROGRAM — COSTS ($000) — Utility — Incentives	Utility — Administration	Utility — Total	Partners — Incentives	Partners — Administration	Partners — Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) — Gross	Net-to-Gross	Net	LIFE — Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2009															
RESIDENTIAL Energy Efficiency Programs															
Retrofit															
ENERGY STAR Heating System Upgrade-Terasen (Retrofit)	1,098	101	1,199	-	-	-	1,502	2,700	44%	-	56%	48,916	57%	27,882	18
EnerChoice Fireplaces (Retrofit)	30	31	60	-	-	-	67	128	47%	-	53%	4,588	76%	3,487	15
ENERGY STAR Heating System Upgrade -Livesmart BC (Retrofit)	848	7	854	-	-	-	1,160	2,014	42%	-	58%	37,776	57%	21,532	18
Total Residential	1,975	138	2,113	-	-	-	2,729	4,842	44%	-	56%	91,279		52,901	

2009 Residential Energy Efficiency Programs	ALTERNATE Impact — Energy MWh	Capacity kW	NET — Levelized Cost ($/GJ)	BENEFIT/COST — Utility Benefits (Costs) — Program ($'000s)	Alternate ($'000s)	Participant Benefits (Costs) — Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings — Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Participant — Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2009																		
RESIDENTIAL Energy Efficiency Programs																		
Retrofit																		
ENERGY STAR Heating System Upgrade-Terasen (Retrofit)	-	-	4	3,020	N/A	2,959	428	N/A	293,682	-	-	2.5191049	1501.722	3,386	2.3	0.7	1.1	319
EnerChoice Fireplaces (Retrofit)	-	-	2	330	N/A	332	48	N/A	33,062	0	-	5.5	67	380	5.6	0.8	2.6	203
ENERGY STAR Heating System Upgrade -Livesmart BC (Retrofit)	-	-	4	2,332	N/A	2,285	330	N/A	226,799	0	-	2.7	1,160	2,615	2.3	0.7	1.2	318
Total Residential	0	0	4	5,682	0	5,575	806	0	553,543	0	0	2.7	2,729	6,381	2.3	0.7	1.2	840

TERASEN GAS VANCOUVER ISLAND

2009 Residential Energy Efficiency Programs	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	Input (program)	J	K	L
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	IxJ	Program
2009															
Residential Energy Efficiency Programs:															
Retrofit															
ENERGY STAR Heating System Upgrade-Live Smart BC (Retrofit)	16	0	16	-	-	-	22	38	42%	-	58%	724	57%	413	18
EnerChoice Fireplaces (Retrofit)	10	14	24	-	-	-	23	47	51%	-	49%	1,566	76%	1,190	15
ENERGY STAR Heating System Upgrade -Terasen (Retrofit)	21	14	35	-	-	-	28	63	55%	-	45%	925	57%	527	18
Total Residential	47	28	75	-	-	-	74	149	51%	-	49%	3,214		2,130	

2009 Residential Energy Efficiency Programs	ALTERNATE		NET	BENEFIT/COST															
	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant						
	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2009																		
Residential Energy Efficiency Programs:																		
Retrofit																		
ENERGY STAR Heating System Upgrade-Live Smart BC (Retrofit)	-	-	4	44	N/A	64	6	N/A	4,322	-	-	2.7	22	70	3.2	0.6	1.2	6
EnerChoice Fireplaces (Retrofit)	-	-	2	112	N/A	166	16	N/A	11,223	-	-	4.6	23	182	7.9	0.6	2.4	65
ENERGY STAR Heating System Upgrade -Terasen (Retrofit)	-	-	6	57	N/A	82	8	N/A	5,519	-	-	1.62116526	28.386	90	3.2	0.5	0.9	(7)
Total Residential	-	-	4	213	0	311	31	0	21,063	0	0	2.8	74	342	4.6	0.6	1.4	64

TERASEN GAS INC

2009 Conservation for Affordable Housing project	PROGRAM										
	COSTS ($000)										
	Utility			Partners							
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant
Label	B	C	D	E	F	G	H	I	J	K	L
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I
2009											
RESIDENTIAL:											
Retrofit											
Meridian Village Furnace Upgrade	229	0	230	161	-	161	229	620	37%	26%	37%
2009 Total Residential	229	0	230	161	-	161	229	620	37%	26%	37%

2009 Conservation for Affordable Housing project	PROGRAM				ALTERNATE		NET BENEFIT/COST									
	SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings			
	Gross	Net-to-Gross	Net	Years	Energy MWh	Capacity kW	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)
Label	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)
2009															
RESIDENTIAL:															
Retrofit															
Meridian Village Furnace Upgrade	1,352	100%	1,352	18	138	-	16	146	179	143	21	123	14,236	1,492	-
2009 Total Residential	1,352		1,352		138	0	16	146	179	143	21	123	14,236	1,492	0

2009 Conservation for Affordable Housing project		Participant				TRC			
	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas	Without 30% adder		UCA Demand-side Measures Regulation (Benefit @ 130%)	
	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)	Total Resource	TRC Net Benefits ($'000s)
Label	AB	AC	AD	AE	AF	AG	AH	AI	AJ
	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	(T+U)*1.3 /I	((T+U)*1.3) I
2009									
RESIDENTIAL:									
Retrofit									
Meridian Village Furnace Upgrade	0.6	229	288	1.3	0.4	0.5	(295)	0.7	(197.3)
2009 Total Residential	0.6371717	229.4	288	1.3	0.4	0.5	(295)	0.7	(197.3)

TERASEN GAS INC

2009 Joint Initiatives	PROGRAM: COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Partners Incentives	Partners Administration	Partners Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) Gross	Net-to-Gross	Net	LIFE Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2009															
Joint Initiatives															
Tier 3 ENERGY STAR Washer / Dryer Rebates	7	0	7	-	-	-	19	25	26%	-	74%	368	57%	210	14
2009 Total Residential	7	0	7	-	-	-	19	25	26%	-	74%	368		210	

2009 Joint Initiatives	ALTERNATE Impact Energy MWh	Impact Capacity kW	NET BENEFIT/COST Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Participant Benefits (Costs) Carbon Tax ($'000s)	Participant Benefits (Costs) Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Program Net Savings Alternate Energy (MWh)	Program Net Savings Alternate Capacity (kW)	Natural Gas Utility	Participant Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2009																		
Joint Initiatives																		
Tier 3 ENERGY STAR Washer / Dryer Rebates	-	-	3	19	N/A	19	3	N/A	1,905	-	-	2.9	19	22	1.2	0.7	0.8	(6)
2009 Total Residential	-	-	3	19	0	19	3	0	1,905	0	0	2.9	19	22	1.2	0.7	0.8	(6)

2010 DSM PLAN

2010 DSM PLAN TGI and TGVI	PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	Mwh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	Mwh	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2010																											
Residential Energy Efficiency Programs																											
Retrofit	2,791	220	3,011	2,868	5,879	51%	49%	119,210	74,906	0	-	4	7,980	0	7,898	1,149	0	755,601	-	-	2.7	2,868	9,048	3.2	0.7	1.4	2,101
2010 Total Residential	2,791	220	3,011	2,868	**5,879**	**51%**	**49%**	**119,210**	**74,906**	**0**	-	**4**	**7,980**	**0**	**7,898**	**1,149**	**0**	**755,601**	**0**	-	2.7	2,868	9,048	3.2	0.7	1.4	2,101
Commercial Energy Efficiency Programs																											
New Construction	221	55	278	518	794	35%	65%	16,291	13,694	0	-	2	1,571	0	1,606	216	0	146,214	-	-	5.6	518	1,822	3.5	0.8	2.0	777
Retrofit	1,305	292	1,619	3,228	4,826	34%	67%	118,150	98,868	0	-	2	10,317	0	9,921	1,412	0	960,490	-	-	6.4	3,228	11,332	3.5	0.9	2.1	5,491
2010 Total Commercial	**1,527**	**346**	**1,898**	**3,746**	**5,620**	**34%**	**67%**	**134,441**	**112,562**	**0**	-	**2**	**11,887**	**0**	**11,526**	**1,628**	**0**	**1,106,704**	**-**	-	**6.3**	**3,746**	**13,154**	**3.5**	**0.9**	**2.1**	**6,267**
High carbon fuel switching																											
High carbon fuel switching	750	225	975	0	975	100%	0%	-32,250	-16,125	9,583		FS	-1,799	4,071	-2,264	122	4,264	(169,145)	50,173	-	FS	2,142	4,264	2.0	0.8	1.5	1,298
Conservation for Affordable Housing	5,661	567	6,229	0	6,229	100%	0%	**39,163**	37,382	**698**	**0**	18	**5,151**	**1,015**	**3,659**	**490**	**538**	**337,855**	**6,507**	**0**	0.8	-	4,688	N/A	0.5	1.0	(63)
SUBTOTALS:																											
Program Subtotal	10,729	1,358	12,113	6,614	18,702	**65%**	**35%**	**260,563**	**208,725**	**10,281**	**0**	**6.0**	**23,220**	**5,086**	**20,820**	**3,390**	**4,802**	**2,031,015**	**56,680**	**0**	**1.9**	**6,614**	**29,012**	**4.4**	**0.7**	**1.5**	**9,604**
Portfolio Level Expenditures																											
Conservation Education & Outreach		1,775																									
Joint Initiatives		717																									
Energy efficiency partners and codes & standards		439																									
Conservation Potential Review		500																									
Research, Evalution & Training		907																									
Consultant		100																									
DSMS System		704																									
Interruptible Industrial DSM		435																									
Pilot Studies		1,433																									
Non program admin		1,545																									
Total		**8,553**																									
2010 Planned Total	**10,729**	**9,912**	**20,640**	**6,614**	**27,254**	**76%**	**24%**	**260,563**	**208,725**	**10,281**	**0**	**10**	**23,220**	**5,086**	**20,820**	**3,390**	**4,802**	**2,031,015**	**56,680**	**0**	**1.1**	**6,614**	**29,012**	**4.4**	**0.6**	**1.0**	**1,052**

TERASEN GAS INC

2010 TGI Planned Programs

2010 TGI Planned Programs	PROGRAM									ALTERNATE	
	COSTS ($000)							SAVINGS (GJ)		Impact	
	Utility									Energy	Capacity
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWH	kW
2010											
Residential Energy Efficiency Programs											
Retrofit											
Energy Efficiency	2,561	180	2,741	2,711	5,452	50%	50%	109,803	68,385	0	-
2010 Residential Total	**2,561**	**180**	**2,741**	**2,711**	5,452	50%	50%	**109,803**	**68,385**	**0**	**-**
High Carbon Fuel Substitution	225	25	250	0	250	100%	0%	-9,675	-4,838	2,875	-
Commercial Energy Efficiency Programs											
New Construction	179	39	221	416	635	35%	65%	12,776	10,775	0	-
Retrofit	1,153	238	1,413	2,854	4,245	33%	67%	103,855	86,955	0	-
2010 Total Commercial	**1,332**	**277**	**1,634**	**3,269**	**4,879**	**33%**	**67%**	**116,631**	**97,730**	**0**	**0**
Conservation for Affordable Housing	4,529	454	4,983	0	4,983	56%		31,330	29,905	558	
portfolio level expenditure											
Conservation Education & Outreach		1,420									
Joint Initiatives		573									
Energy efficiency partners and codes & standards		351									
Conservation Potential Review		400									
Research, Evalution & Training		777									
Consultant		80									
DSMS System		563									
Interruptible Industrial DSM		435									
Pilot Studies		1,146									
Non program admin		1,236									
total		**6,981**									
2010 Planned Total	**8,647**	**7,917**	**16,565**	**5,981**	**22,546**	**73%**	**27%**	**248,089**	**191,183**	**3,433**	**0**

2010 TGI Planned Programs	NET PRESENT VALUE									BENEFIT/COST						
	Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	Mwh	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2010																
Residential Energy Efficiency Programs																
Retrofit																
Energy Efficiency	4	7,324	0	6,970	1,053	0	692,757	-	-	2.7	2,711	8,024	3.0	0.8	1.3	1,871
2010 Residential Total	**10**	**7,324**	**0**	**6,970**	**1,053**	**0**	**692,757**	**0**	**0**	2.7	2,711	8,024	3.0	0.8	1.3	1,871
High Carbon Fuel Substitution	FS	-540	1,226	-513	52	1,261	-50,954	15,052	-	FS	461	1,261	2.7	0.7	1.6	437
Commercial Energy Efficiency Programs																
New Construction	2	1,230	0	1,084	169	0	114,570	-	-	5.6	416	1,253	3.0	0.9	1.9	595
Retrofit	2	9,048	0	7,976	1,237	0	842,412	-	-	6.4	2,854	9,213	3.2	1.0	2.1	4,803
2010 Total Commercial	**2**	**10,277**	**0**	**9,060**	**1,406**	**0**	**956,981**	**-**	**-**	**6.3**	**3,269**	**10,466**	**3.2**	**1.0**	**2.1**	**5,398**
Conservation for Affordable Housing	10	4124.9	812.0	2,711	392	430	270,285	5,205		1	-	3,533	0	0.6	1.0	-46
2010 Planned Total	**8.9**	**21,186**	**2,038**	**18,228**	**2,903**	**1,691**	**1,869,069**	**20,257**	**0**	**1.3**	**5,981**	**22,823**	**3.8**	**0.6**	**1.0**	**679**

TERASEN GAS VANCOUVER ISLAND

2010 TGVI Planned Programs	PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWH	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	MWH	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2010																											
Residential Energy Efficiency Programs																											
Retrofit																											
Energy Efficiency	230	40	270	156	426	63%	37%	9,407	6,521	0	-	4	656	0	928	96	0	62,844	-	-	2.4	156	1,024	6.6	0.5	1.5	230
2010 Residential Total	**230**	**40**	**270**	**156**	**426**	**63%**	**37%**	**9,407**	**6,521**	**0**	**0**	**4**	**656**	**0**	**928**	**96**	**0**	**62,844**	**0**	**0**	**2**	**156**	**1,024**	**7**	**1**	**1.5**	**230**
High Carbon fuel switching																											
High Carbon fuel switching	525	200	725	0	725	100%	0%	-22,575	-11,288	6,708	-	FS	-1,259	2,845	-1,751	70	3,003	-118,191	35,121	-	FS	1,680	3,003	1.8	0.9	1.4	861
Commercial Energy Efficiency Programs																											
New Construction	42	16	57	102	159	36%	64%	3,515	2,918	0	-	2	341	0	521	47	0	31,645	-	-	5.8	102	568	5.6	0.6	2.1	182
Retrofit	152	54	206	375	581	36%	64%	14,295	11,913	0	-	2	1,269	0	1,945	175	0	118,078	-	-	6.0	375	2,119	5.7	0.6	2.2	688
2010 Total Commercial	**194**	**69**	**264**	**477**	**741**	**36%**	**64%**	**17,810**	**14,832**	**0**	**-**	**2**	**1,610**	**0**	**2,466**	**222**	**0**	**149,722**	**-**	**-**	**6.0**	**477**	**2,688**	**5.6**	**0.6**	**2.2**	**870**
Conservation for Affordable Housing	1132	113	1246	0	1246	56%	44%	7832	7476	140		10	1026	203	948	98	108	67571	1,301	-	1	0	1154	0	0	1.0	-17
portfolio level expenditure																											
Conservation Education & Outreach		355																									
Joint Initiatives		143																									
Energy efficiency partners and codes & standards		88																									
Conservation Potential Review		100																									
Research, Evalution & Training		130																									
Consultant		20																									
DSMS System		141																									
Pilot Studies		287																									
Non program admin		309																									
		$ 1,572																									
2010 Planned Total	**2,081**	**1,994**	**4,076**	**633**	**4,709**	**87%**	**13%**	**12,474**	**17,542**	**6,848**	**0**	**25**	**2,033**	**3,048**	**2,592**	**486**	**3,111**	**161,946**	**36,423**	**0**	**0.5**	**633**	**6,189**	**9.8**	**0.3**	**1.1**	**373**

2010 planned commercial energy efficiency programs

TGI

	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
Commercial Energy Efficiency Programs															
New Construction															
Efficient Boiler Program	103	13	116	-	-	-	296	412	28%	-	72%	8,704	82%	7,137	20
Light Comm. ENERGY STAR® Boiler Program	14	9	24	-	-	-	28	52	46%	-	54%	1,772	82%	1,453	20
Efficient Commercial Water Heater	62	17	79	-	-	-	91	170	46%	-	54%	2,300	95%	2,185	13
Retrofit															
Retrofit Efficient Boiler Program	835	107	942	-	-	-	2,408	3,350	28%	-	72%	70,720	82%	57,990	20
Retrofit Light Comm. ENERGY STAR® Boiler Program	115	75	190	-	-	-	227	416	46%	-	54%	14,160	82%	11,611	20
Retrofit Efficient Commercial Water Heater	149	41	190	-	-	-	219	409	46%	-	54%	5,520	95%	5,244	13
Retrofit Energy Assesment	54	16	70	-	-	-	0	70	100%	-	0%	13,455	90%	12,110	2
2010 Total Commercial	1,332	278	1,610	-	-	-	3,269	4,879	33%	-	67%	116,631		97,730	108
Retrofit & New Consctruction															
Efficient Boiler Program	938	120	1058	0	0	0	2705	3762	0	0	1	79424	1	65128	20
Light Comm. ENERGY STAR® Boiler Program	129	84	213	0	0	0	255	468	0	0	1	15932	1	13064	20
Efficient Commercial Water Heater	211	58	269	0	0	0	310	579	0	0	1	7820	1	7429	13

	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	Impact		Levelized Cost	Utility Benefits		Participant Benefits (Costs)			Program Net Savings				Participant					
	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
Commercial Energy Efficiency Programs																		
New Construction																		
Efficient Boiler Program	-	-	1	861	N/A	753	118	N/A	79,461	-	-	7.4	296	871	2.9	1.0	2.1	449
Light Comm. ENERGY STAR® Boiler Program	-	-	1	175	N/A	153	24	N/A	16,177	-	-	7.4	28	177	6.3	1.0	3.4	123
Efficient Commercial Water Heater	-	-	4	193	N/A	178	27	N/A	18,932	-	-	2.4	91	205	2.3	0.8	1.1	23
Retrofit																		
Retrofit Efficient Boiler Program	-	-	1	6,998	N/A	6,119	955	N/A	645,619	-	-	7.4	2,408	7,074	2.9	1.0	2.1	3,648
Retrofit Light Comm. ENERGY STAR® Boiler Program	-	-	1	1,401	N/A	1,225	191	N/A	129,270	-	-	7.4	227	1,417	6.3	1.0	3.4	985
Retrofit Efficient Commercial Water Heater	-	-	4	463	N/A	427	66	N/A	45,436	-	-	2.4	219	493	2.3	0.8	1.1	54
Retrofit Energy Assesment	-	-	3	185	N/A	204	25	N/A	22,087	-	-	2.6	-	229	N/A	0.7	2.6	115
2010 Total Commercial	-	-	2	10,277	0	9,060	1,406	0	956,981	-	-	6.4	3,269	10,466	3.2	1.0	2.1	5,398
Retrofit & New Consctruction																		
Efficient Boiler Program	-	-	1	7860		6872	1073		725,080			7	2705	7945	2.9	1.0	2.1	4097
Light Comm. ENERGY STAR® Boiler Program	-	-	1	1577		1379	215		145,447			7	255	1594	6.3	1.0	3.4	1108
Efficient Commercial Water Heater	-	-	4	656		605	93		64,368			2	310	698	2.3	0.8	1.1	77

TERASEN GAS VANCOUVER ISLAND

2010 planned Commercial energy efficiency programs

TGVI	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Partners – Incentives	Partners – Administration	Partners – Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) – Gross	Net-to-Gross	Net	LIFE – Years	ALTERNATE – Impact – Energy MWh	Capacity kW	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits – Program ($'000s)	Utility Benefits – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	Participant – Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	B	C	D	E	F	G	H	I	J	K	L	Input (program)	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	IxJ	Program	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
2010																																	
Commercial Energy Efficiency Programs																																	
New Construction																																	
Efficient Boiler Program	26	6	32	-	-	-	74	106	30%	-	70%	2,176	82%	1,784	20	-	-	2	214	N/A	325	29.4	N/A	19,739	-	-	6.7	74	355	4.8	0.6	2.0	108
Light Comm. ENERGY STAR® Boiler Program	9	5	13	-	-	-	17	30	44%	-	56%	1,063	82%	872	20	-	-	1	104	N/A	159	14.4	N/A	9,644	-	-	7.7	17	173	10.2	0.6	3.4	74
Efficient Commercial Water Heater	7	5	12	-	-	-	11	23	53%	-	47%	276	95%	262	13	-	-	5	23	N/A	37	3.3	N/A	2,261	-	-	1.9	11	40	3.7	0.5	1.0	(0)
Retrofit																																	
Efficient Boiler Program	103	24	127	-	-	-	296	423	30%	-	70%	8,704	82%	7,137	20	-	-	2	855	N/A	1,302	117.6	N/A	78,955	-	-	6.7	296	1,419	4.8	0.6	2.0	431
Light Comm. ENERGY STAR® Boiler Program	29	16	45	-	-	-	57	102	44%	-	56%	3,544	82%	2,906	20	-	-	1	348	N/A	530	47.9	N/A	32,148	-	-	7.7	57	578	10.2	0.6	3.4	246
Retrofit Efficient Commercial Water Heater Program	15	10	25	-	-	-	22	46	53%	-	47%	552	95%	524	13	-	-	5	46	N/A	74	6.6	N/A	4,523	-	-	1.9	22	80	3.7	0.5	1.0	(0)
Retrofit Energy Assesment Program	6	4	10	-	-	-	-	10	100%	-	0%	1,495	90%	1,346	2	-	-	4	21	N/A	39	2.8	N/A	2,451	-	-	2.1	-	42	N/A	0.4	2.1	11
Total Commercial	194	69	264	-	-	-	477	741				17,810		14,832		0	-	2	1,610	0	2,466	222	0	149,722	-	-	6.1	477	2,688	5.6	0.6	2.2	870
New Construction and Retrofit Combined																																	
Efficient Boiler Program	128	30	158	-	-	-	370	529	30%	-	70%	10,880	82%	8,922	20	-	-	2	1,068		1,627	147		98,694			6.7	370	1,774	4.8	0.6	2.0	539
Light Comm. ENERGY STAR® Boiler Program	37	21	58	-	-	-	74	132	44%	-	56%	4,607	82%	3,778	20	-	-	1	452		689	62		41,793			7.7	74	751	10.2	0.6	3.4	320
Efficient Commercial Water Heater	22	14	37	-	-	-	33	70	53%	-	47%	828	95%	787	13	-	-	5	69		111	10		6,784			1.9	33	121	3.7	0.5	1.0	(1)

TERASEN GAS INC

2010 planned Residential Energy Efficiency Programs	PROGRAM														
TGI	COSTS ($000)											SAVINGS (GJ)			LIFE
	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
Residential Energy Efficiency Programs															
Retrofit															
Energy Efficiency															
ENERGY STAR Heating System Upgrade_Terasen (Retrofit)	902	40	942	-	-	-	1,234	2,177	43%	-	57%	40,204	57%	22,916	18
EnerChoice Fireplaces (Retrofit)	450	50	500	-	-	-	114	614	81%	-	19%	23,250	76%	17,670	15
ENERGY STAR Hot Water Heaters (Retrofit)	300	80	380	-	-	-	120	500	76%	-	24%	6,000	80%	4,800	13
ENERGY STAR Heating System Upgrade_Live Smart BC (Retrofit)	909	10	919	-	-	-	1,243	2,162	42%	-	58%	40,349	57%	22,999	18
High Carbon Fuel Switching															
Switch 'N' Shrink High Carbon Fuel Switching	225	25	250				0	250	100%	-	0%	-9,675	50%	-4,838	18
2010															
Total Residential	2,786	205	2,991	-	-	-	2,711	5,702	52%	-	48%	100,128		63,548	

2010 planned Residential Energy Efficiency Programs	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST							
TGI	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Mwh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	Mwh	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
Residential Energy Efficiency Programs																		
Retrofit																		
Energy Efficiency																		
ENERGY STAR Heating System Upgrade_Terasen (Retrofit)	-	-	3.90	2,575	N/A	2,432	367	N/A	241,380	-	-	2.7	1,234	2,798	2.3	0.8	1.2	398
EnerChoice Fireplaces (Retrofit)	-	-	3	1,741	N/A	1,682	255	N/A	167,542	-	-	3.5	114	1,937	17.0	0.8	2.8	1,127
ENERGY STAR Hot Water Heaters (Retrofit)	-	-	9	424	N/A	416	63	N/A	41,589	-	-	1.1	120	480	4.0	0.5	0.8	(76)
ENERGY STAR Heating System Upgrade_Live Smart BC (Retrofit)	-	-	4	2,584	N/A	2,440	368	N/A	242,246	-	-	2.8	1,243	2,808	2.3	0.8	1.2	422
High Carbon Fuel Switching																		
Switch 'N' Shrink High Carbon Fuel Switching	2,875	-	FS	(540)	1,226	(513)	52	1,261	(50,954)	15,052	-	FS	461	1,261	2.7	0.7	1.6	437
2010																		
Total Residential	0	-	5	6,784	1,226	6,457	1,105	0	641,803	-	-	2.3	2,711	7,562	2.8	0.7	1.4	2,308

TERASEN GAS VANCOUVER ISLAND

2010 planned Residential energy efficiency programs

TGVI	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Partners – Incentives	Partners – Administration	Partners – Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) – Gross	Net-to-Gross	Net	LIFE – Years
Label	B	C	D	E	F	G	H	I	J	K	L	Input (program)	J	K	L
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	IxJ	Program
2010															
<u>RESIDENTIAL:</u>															
High carbon Fuel Switching															
Switch 'N' Shrink High Carbon Fuel Switching	525	200	725	-	-	-	0	725	100%	-	0%	-22,575	50%	-11,288	18
Energy Efficiency															
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	60	20	80	-	-	-	24	104	77%	-	23%	1,200	80%	960	13
EnerChoice Fireplaces (Retrofit)	90	10	100	-	-	-	23	123	81%	-	19%	4,650	76%	3,534	15
ENERGY STAR Heating System Upgrade - Terasen (Retrofit)	30	5	35	-	-	-	41	76	46%	-	54%	1,337	57%	762	18
ENERGY STAR Heating System Upgrade_LiveSmart BC (Retrofit)	50	5	55	-	-	-	68	123	45%	-	55%	2,220	57%	1,265	18
Total Residential	755	240	995	-	-	-	156	1,151	86%	-	14%	-13,168		-4,766	

TGVI	ALTERNATE – Impact – Energy Mwh	Impact – Capacity kW	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits – Program ($'000s)	Utility Benefits – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy Mwh	Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
	Program	Program	D/U	KxAF	M x J x AH	J x I x AJ	J x I x AK	J x (MxAL + NxAM)	PV(AE,L,-K)	PV(AG,L,-M)	PV(AG,L,-N)	P/D	E>0, (R+S)<0	E<0, (R+S)>0, T	Z/Y	P/(R+D)	(P+Q)/F	(P+Q)-F
High carbon Fuel Switching																		
Switch 'N' Shrink High Carbon Fuel Switching	6,708	-	FS	(1,259)	2,845	(1,751)	70	3,003	(118,191)	35,121	-	FS	1,680	3,003	1.8	0.9	1.4	861
Energy Efficiency																		
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	-	-	10	84	N/A	122	13	N/A	8,280	-	-	1.1	24	134	5.6	0.4	0.8	(20)
EnerChoice Fireplaces (Retrofit)	-	-	3	346	N/A	492	51	N/A	33,336	-	-	3.5	23	543	23.8	0.6	2.8	223
ENERGY STAR Heating System Upgrade - Terasen (Retrofit)	-	-	4	85	N/A	118	12	N/A	7,979	-	-	2.4	41	130	3.2	0.6	1.1	9
ENERGY STAR Heating System Upgrade_LiveSmart BC (Retrofit)	-	-	4	141	N/A	196	20	N/A	13,250	-	-	2.6	68	217	3.2	0.6	1.1	18
Total Residential	6,708	-	FS	-603	2,845	-823	166	3,003	(55,347)	35,121	-	FS	813	3,003	3.7	0.5	1.6	1,091

TERASEN GAS INC

2010 planned Conservation for Affordable Housing Programs	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
TGI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
RESIDENTIAL:															
Retrofit															
Energy Savings Kits	130	150	280	-	-	-	0	280	100%	-	0%	4,290	92%	3,947	8
Energy Conservation Assistance Program	2,200	304	2,504	2,200	-	2,200	0	4,703	53%	0	0%	27,040	96%	25,958	15
Total Residential	2,329	454	2,784	2,200	-	2,200	0	4,983	56%	0	0%	31,330		29,905	

2010 planned Conservation for Affordable Housing Programs	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST								
	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant				TRC			
TGI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas	Without 30% adder		UCA Demand-side Measures Regulation (Benefit @ 130%)	
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	(T+U)*1.3 /I	((T+U)*1.3) -I
RESIDENTIAL:																				
Retrofit																				
Energy Savings Kits	-	-	12	265	N/A	240	35	N/A	24,155	-	-	0.9	-	275	N/A	0.5	0.9	(14)	1.2	65
Energy Conservation Assistance Program	558	-	10	2,908	625	2,471	357	430	246,130	5,205	-	1.2	-	3,258	N/A	0.6	0.8	(1,171)	1.0	(111)
Total Residential	558	0	10	3,173	625	2,711	392	430	270,285	5,205	0	1.1	-	3,533	N/A	0.6	0.8	(1,186)	1.0	(46)

TERASEN GAS VANCOUVER ISLAND

	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
2010 planned Conservation for Affordable Housing Programs	Utility			Partners											Years
TGVI	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
RESIDENTIAL:															
Retrofit															
Energy Savings Kits	32	37	70	-	-	-	0	70	100%	-	0%	1,072	92%	987	8
Energy Conservation Assistance Program	550	76	626	550	-	550	0	1,176	53%	0	0%	6,760	96%	6,490	15
Total Residential	582	113	696	550	-	550	0	1,246	56%	0	0%	7,832		7,476	

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST									
	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant				TRC			
2010 planned Conservation for Affordable Housing Programs	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas	Without 30% adder		UCA Demand-side Measures Regulation (Benefit @ 130%)	
TGVI	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)	Total Resource	TRC Net Benefits ($'000s)
	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ
	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I	(T+U)*1.3 /I	((T+U)*1.3) -I
RESIDENTIAL:																				
Retrofit																				
Energy Savings Kits	-	-	12	66	N/A	84	9	N/A	6,038	-	-	1.0	-	93	N/A	0.4	1.0	(3)	1.2	17
Energy Conservation Assistance Program	140	-	10	723	156	864	89	108	61,532	1,301	-	1.2	-	1,061	N/A	0.5	0.7	(297)	1.0	(33)
Total Residential	140	0	10	789	156	948	98	108	67,571	1,301	0	1.1	-	1,154	N/A	0.5	0.8	(300)	1.0	(17)

Appendix K

DRAFT ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-XX-XX

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
2009 Annual Energy Efficiency and Conservation Report

BEFORE:

(Date)

WHEREAS:

"Companies")

A. On May 28, 2008, Terasen Gas Inc. ("TGI") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (collectively the "Companies") filed their application for Energy Efficiency and Conservation ("EEC") for 2008-2010; and

B. On April 16, 2009, the Commission issued Order No. G-36-09 and Decision (the "EEC Decision") approving EEC funding for TGI and TGVI for 2009 and 2010; and

C. On November 26, 2009, the Commission issued Order No. G-141-09 approving the TGI 2010-2011 Negotiated Settlement Agreement and Order No. G-140-09 TGVI 2010-2011 Negotiated Settlement Agreement approving further EEC funding for 2011 for both Companies; and

D. The EEC Decision on page 42 directed the Companies to file annual EEC Reports on all EEC initiatives and activities, expenditures and results by the end of the first quarter of the following year-end and for each year of the funding period; and

E. On March 31, 2010, the Companies filed their 2009 EEC Annual Report; and

F. The Companies seek Commission acceptance of their 2009 EEC Annual Report; and

G. The Companies request approval for the attribution of savings from regulation to be on a case-by-case basis; and

H. The Companies also seek approval for the attribution of 6 years of post-regulation savings to a Condensing Water Heater Initiative to support government's proposed minimum efficiency threshold of 0.80 EF for residential water heaters; and

I. The Commission has reviewed the 2009 EEC Annual Report and orders the following.

NOW THEREFORE the Commission orders as follows:

1. The 2009 EEC Report is accepted.

2. The attribution of savings from regulation to be on a case-by-case basis is approved.

3. The attribution of 6 years of post-regulation savings to a Condensing Water Heater Initiative is approved.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

Appendix K-4

FEI-FEVI 2010 EEC REPORT

Provided in electronic format only

Diane Roy
Director, Regulatory Affairs Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 31, 2011

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") (collectively the "Companies")
Energy Efficiency and Conservation Program - 2010 Annual Report

British Columbia Utilities Commission (the "Commission") Decision dated April 16, 2009 and Order No. G-36-09 Compliance Filing

---

On April 16, 2009, the Commission issued its Decision and Order No. G-36-09 ("Decision") on the Companies' Energy Efficiency and Conservation ("EEC") Application approving funding for FEI and FEVI for 2009 and 2010 programs.

In the Decision, the Companies were directed to file annual EEC report on all of the EEC initiatives and activities, expenditures, and results by the end of the first quarter following year-end.

Further funding for 2010-2011 was approved for each of the Companies in their respective 2010-2011 Revenue Requirements Application ("RRA") Negotiated Settlement Agreements approved by the Commission on November 26, 2009 for FEI by Order No. G-141-09 and FEVI by Order No. G-140-09.

Pursuant to the Decision, the Companies enclose their second annual report, the EEC Annual Report for 2010 (the "Report"). The Companies respectfully request that the Commission review the majority of the Report and raise any associated inquiries in the regulatory process that will be established for the Companies' upcoming Revenue Requirements Application, which will be filed with the Commission by May 2011. The Companies will file the Report as part of its RRA; therefore, the Companies believe that it is most efficient to consolidate the review of the 2010 EEC activity in the same process where the Companies will be seeking further funding for 2012-2013, as there is bound to be overlap in the substance of any inquiries.

The only exception to this approach to reviewing the Report is with respect to the use of EEC funds to provide an incentive to the customer to offset the cost of buying a natural gas vehicle (e.g. truck) versus the standard diesel or gasoline option. The information with regard to EEC funds being used for Natural Gas Vehicles ("NGV") is contained in the section of the Report relating to Innovative Technologies Program Area funding (Section 10.2). The

Companies wish to have this addressed at the earliest possible date for the reasons discussed below.

In the Decision accompanying Order No. G-6-11, dated January 14, 2011, relating to the interim approval of a Compressed Natural Gas service agreement with Waste Management, the Commission raised an issue about the Companies' provision of incentive funding for NGV initiatives. The Companies are of the view that NGVs are a part of the approved incentive funding for the innovative technologies program area, and the use of incentive funding for NGVs meets the requirements established by the Commission to ensure EEC funding is cost-effective. However, it has been necessary for the Companies to hold up new EEC incentive funding for NGV pending clarification of this issue. It is important that the Companies and the Commission reach concurrence on this issue in a timely manner, so that we can move forward on new projects that provide benefits to existing natural gas customers and fleet owners while helping to meet the energy objectives of the provincial government.

The Report (at page 201) provides additional explanation that was not available in the record of the NGV application proceeding as to why the Companies believe they have acted according to past Commission decisions. In this regard:

- We have made specific reference to past decisions, and have explained how the incentive funding was subjected to a transparent review process to ensure its cost-effectiveness.

- We have also obtained input from stakeholders involved in the EEC review process established to oversee the use of EEC funding that were aware of, and endorse, the use of incentive funding for NGVs. When this issue was discussed at the most recent EEC stakeholder group meeting (March 15, 2011), a number of participants at the meeting again verbally expressed support for the Companies' position and a desire for the Companies to proceed with cost-effective funding for NGV. Members of the EEC stakeholder working group and customer groups have since provided letters contained within the Report supporting the Companies' position that EEC funds for NGV have been used appropriately, within the established guidelines (Please see letters of support included in Appendix F).

It is the hope of the Companies that, with the benefit of this additional information, the Commission will be able to quickly provide confirmation of the Companies' compliance with past orders without additional process. Alternatively, if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission provide its concurrence for the Companies to proceed with EEC incentive funding to customers to offset the incremental cost of buying an NGV over a standard gasoline or diesel vehicle. The Companies respectfully submit that this concurrence to proceed could also be provided without additional process since the benefits of EEC incentive funding for NGV are clear, accord with Commission-approved EEC principles, exceed the Commission-approved tests for evaluating EEC funding, and have the support of stakeholders.

If you have any questions regarding this submission in general please contact the undersigned or Sarah Smith, Manager, Energy Efficiency and Conservation at (604) 592-7528. For NGV related questions, please contact Mark Grist, Manager, Business Development at (604) 592-7874.

Yours very truly,

FORTISBC ENERGY INC.
FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Original signed by:

Diane Roy

Attachments

cc (email only): EEC Stakeholder Group

FORTIS BC™

FortisBC Energy Inc. and
FortisBC Energy (Vancouver Island) Inc.

Energy Efficiency and Conservation Programs
2010 Annual Report

March 31, 2011

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1 REPORT OVERVIEW

1.1 Background

FortisBC Energy Inc. ("FortisBC" or "FEI", formally known as "Terasen Gas Inc." or "TGI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI", formally known as "Terasen Gas (Vancouver Island) Inc." or "TGVI") (collectively referred to as "the Companies") have been involved with Energy Efficiency and Conservation ("EEC") since the 1990s. The Companies' earlier EEC activities were referred to in previous regulatory filings with the British Columbia Utilities Commission (the "Commission" or the "BCUC") as Demand Side Management ("DSM") activity. On May 28, 2008, TGI and TGVI collectively filed their Energy Efficiency and Conservation Programs Application (the "EEC Application"), seeking approval of increased funding of EEC programs for the timeframe of 2008-2010. On April 16, 2009, the Commission released its decision on the EEC Application and Order No. G-36-09[1] (the "EEC Decision"), which approved funding in aggregate of $41.5 million ($34.4 million for TGI and $7.1 million for TGVI). A further $32.35 million in EEC expenditure for TGI and $6.1 million for TGVI was approved as part of the Commission Orders G-141-09[2] and G-140-09[3], dated November 26, 2009, approving Negotiated Settlement Agreements ("NSAs") in the 2010 – 2011 Revenue Requirement Applications for TGI and TGVI respectively.

Similar to the Companies' 2009 EEC report, this EEC Annual Report (the "Report") outlines the Companies' actual (for 2010) and planned (for 2011) activities and associated expenditures related to these three Orders. As the Report will describe, the Companies are making prudent and appropriate use of the approved funds to promote EEC activities, which help customers save money and at the same time support the province's energy policy goals.

The following sections outline the purpose of this Report and its content.

1.2 EEC Annual Report: Taking Accountability and Taking Stock of Progress

This Report serves two purposes.

First, this Report demonstrates that the Companies are meeting the accountability mechanisms accepted by the Commission in Order No. G-36-09. One such mechanism was the requirement to file EEC Annual Reports, which states as follows:

> *"A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI."*[4]

The first EEC Annual Report was filed with the Commission on March 31, 2010, outlining the 2009 actual activity results and 2010 planned activities. This Report is the second EEC Annual

[1] Appendix C: DSM Regulation and BCUC Orders
[2] Ibid
[3] Ibid
[4] EEC Decision, page 2

Report since accountability mechanisms were accepted by the Commission as part of Order No. G-36-09.

Second, this Report provides the evaluation and assessment of the Companies' success with activities in each Program Area and on a portfolio level as requested in the EEC Decisions. Specifically, the Commission required the following information be included in the EEC Annual Reports:

> *"The Commission panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.*
>
> *Commission Panel directs that the annual EEC Report include the following:*
>
> - TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.
> - Any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.
> - Data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.
>
> *The Commission Panel also directs Terasen to include in its annual EEC Report to the Commission a discussion of its internal data gathering, monitoring and reporting control processes. The discussion should include a description of how these processes ensure that funds expended and the statistical results of the programs implemented are completely and accurately recorded and monitored, including any related internal check and audit processes. The report should also discuss how Terasen has measured or estimated the results of the EEC expenditure initiatives."*[5]

The Commission also directed the Companies to redesign and resubmit the Attribution to Regulatory Change with its next EEC Annual Report, "reflecting the provisions of the DSM regulation which come into effect for [the Companies] on June 1, 2009"[6]. In the 2009 EEC Annual Report, the Companies requested Commission approval of attribution of savings from regulation to be on a case-by-case basis. The Companies also sought approval to attribute six years of post-regulation savings to a market transformation initiative for condensing water heaters. The Companies have not received approval from the Commission on attribution matters; therefore, these two requests for approval related to attribution matters have not been implemented. The Companies have not made any requests for approval on any matters related to attribution in this report. Any requests for attribution-related approvals will be incorporated

[5] Ibid, page 42
[6] Ibid, page 40

into the next request for EEC funding approval, to be submitted with the Companies' next Revenue Requirements Application in the spring of 2011.

This Report provides TRC calculations for each program, Program Area, and Portfolio in Section 2. The remaining California Standard Practice Test results (RIM, Participant Cost Test, and Utility Cost Test) are provided in Appendix B.

1.3 Organization of the EEC Annual Report

The Companies believe this EEC Annual Report not only satisfies the requirements of the EEC Decision, but also provides a detailed overview of the Companies' efforts to implement a comprehensive EEC initiative and identifies the Companies' plans for EEC activities in 2011, with a view to giving stakeholders an opportunity to comment on the Companies' planned activity.

This Report is organized in the following sections:

Section 1: Overview

- Provides a high-level background, the reason for the report, and this summary of the organization of the report.

Section 2: EEC Activity Overview

- Provides a summary of actual 2010 expenditures and outcomes, an organizational chart for the EEC team, program area funding transfer information, a forecast for known 2011 expenditures and outcomes, and a discussion of the adequacy requirements in the DSM Regulation

Section 3: Residential Energy Efficiency Programs

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Residential Program Area

Section 4: Commercial Energy Efficiency Programs

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Commercial Program Area

Section 5: High Carbon Fuel Switching Programs

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for High Carbon Fuel Switching Programs

Section 6: Conservation for Affordable Housing Programs

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Conservation for Affordable Housing Program Area

Section 7: Joint Initiatives

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Joint Initiatives Program Area

Section 8: Conservation Education and Outreach

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Conservation Education and Outreach Program Area

Section 9: Industrial Sector Programs

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Conservation Education and Outreach Program Area

Section 10, Parts 1 and 2: Innovative Technologies

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the Innovative Technologies Program Area, including a discussion of the Companies' provision of EEC funding to customers to help them to offset the incremental costs of natural gas vehicles over conventionally fuelled vehicles

Section 11: Enabling Activities

- Provides both summary and detail regarding actual 2010 and forecast known 2011 expenditures and outcomes for the enabling activities that support the work of the EEC portfolio as a whole

Section 12: EEC Stakeholder Group Activities

- Provides information regarding EEC Stakeholder Group activities completed in 2010 and 2011

Section 13: Conservation Potential Review

- Provides information about the methodology and delivery schedule for the Companies' Conservation Potential Review study

Section 14: Data Gathering, Reporting and Internal Control Processes

- Provides an update on the implementation of the Companies' DSM Tracking System, a high level description of the Companies' internal approval process for programs, and a high level summary of the findings of the Companies' Internal Audit Services' annual review of the EEC initiative

Section 15: EEC Principles

- Provides a discussion of how the Companies' 2010 and planned 2011 EEC activity meets the Guiding Principles that were initially laid out in the original EEC Application in 2008 for the EEC initiative

1.4 Summary

This report is intended to meet one of the accountability mechanisms originally put forth by the Companies in the EEC Application. It is intended to detail completed 2010 activity, and planned 2011 activity, in a transparent and open manner. The Companies have laid a good foundation in 2010 for future EEC activity, and look forward to implementing and continuing to grow the EEC initiative through 2011 and beyond.

2 OVERVIEW OF 2010 PROGRAM ACTIVITIES

In this Section, the Companies will describe their EEC activities, associated expenditures, and the Total Resource Cost ("TRC") test results on an overall portfolio level in 2010. This section will also provide the TRC results for both the conventional EEC portfolio (defined as all EEC activity outside the Innovative Technology Program Area), and for the Innovative Technology Program Area, which latter program area, in accordance with Commission Orders No. G-140-09 and G-141-09, must have a standalone TRC that is 1.0 or greater.

2.1 TRC Results on Portfolio Level

For FEI and FEVI, the TRC level for the entire EEC portfolio, including both conventional EEC activities and innovative technologies, is at 1.1, meeting the Commission's order as set forth in Commission Order No. G-36-09.

Table 2-1: 2010 Overall EEC Portfolio Results

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	10,548	5,261	15,809	(17,507)	532,929	1.1
FEVI	870	1,022	1,892	22,389	169,030	0.9
Total	**11,418**	**6,283**	**17,701**	**4,882**	**701,959**	**1.1**

The "Annual Energy Savings" number for FEI is negative, meaning from a simple annual perspective, the Companies' 2010 activity resulted in natural gas load growth. This is primarily due to the impact of Natural Gas Vehicles ("NGVs"), which is discussed in some detail in Section 10. It should be noted that NGVs bring load onto the natural gas system, but they displace higher carbon diesel fuel; displaced volumes of diesel fuel are not shown in the table above.

The table below further shows results for each individual program area. One of the program principles put forth in the EEC Application was that of universality; that is, programs should be available to all the Companies' customers. Although the TRC results for the residential and affordable housing program areas are below 1.0, these are crucial areas of activity for the Companies. The Companies have about 850,000 residential customers, which form the bulk of the Companies' approximately 950,000 total number of customers. In creating a culture of conservation in British Columbia, these residential customers are crucial to supporting such a culture. Programs for affordable housing (for low-income customers) are a requirement as outlined in the DSM Regulation for adequacy. These two program areas are discussed in more detail in Sections 6 and 2.7, respectively. Compliance with DSM Regulation requirements for adequacy is discussed below in Section 2.7. Programs for residential customers and customers living in affordable housing are also needed in order the meet the Companies' principle of universality. More discussion of the Companies' EEC program principles can be found in Section 15.

Table 2-2: 2010 Overall EEC Program Area Results

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
Residential Programs	**2,803**	**440**	**62,037**	**606,851**	**0.9**
FEI	2,686	329	59,965	586,021	1.0
FEVI	117	111	2,072	20,830	0.6
Commercial Programs	**2,401**	**169**	**103,856**	**815,113**	**1.7**
FEI	1,964	120	82,678	658,188	1.7
FEVI	437	49	21,178	156,925	1.7
Joint Initiatives	**29**	**429**	**748**	**5,700**	**0.1**
FEI	14	419	748	5,700	0.1
FEVI	15	10	n/a	n/a	n/a
Conservation for Affordable Housing	**49**	**275**	**3,297**	**19,479**	**0.8**
FEI	39	256	2,637	15,520	0.7
FEVI	10	19	660	3,959	1.8
Innovative Technology	**5,959**	**5**	**(161,228)**	**(706,551)**	**1.2**
FEI	5,816	5	(162,911)	(726,396)	1.3
FEVI	143	0	1,683	19,845	0.3
High Carbon Fuel Switching	**178**	**123**	**(3,828)**	**(38,632)**	**1.4**
FEI	29	47	(624)	(6,103)	1.2
FEVI	149	76	(3,204)	(32,529)	1.5
Conservation Education and Outreach		**1,616**			
FEI		1,415			
FEVI		201			
Portfolio Level Activities		**3,226**			
FEI		2,670			
FEVI		556			
Total	**11,418**	**6,283**	**4,882**	**701,959**	**1.1**

2.2 TRC Result for the Conventional Program Area

As Table 2-3 demonstrates below, for the conventional EEC portfolio, which includes all program areas except Innovative Technologies, the TRC score is at 1.0.

Table 2-3: 2010 Overall Program Portfolio Results – Conventional EEC Portfolio

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	4,732	5,256	9,988	145,404	1,259,325	0.9
FEVI	727	1,022	1,749	20,706	149,185	1.1
Total	**5,459**	**6,278**	**11,737**	**166,110**	**1,408,510**	**1.0**

The reasons why the Conventional EEC portfolio for FEI had a TRC level of 0.9 include the complex environment in which the Companies were operating the EEC initiatives in 2010, the relatively low gas prices, and the increase in enabling activities that do not necessarily contribute to energy saving. Each is explained below respectively.

First, both the financial crisis and the changes in provincial government leadership impacted the customers' focus on EEC activities. The financial crisis that started in 2007 continued to affect the economy in British Columbia in 2010. The Companies' commercial customers were constrained by tighter access to credit, and since the customers' focus was on keeping their businesses going during challenging times, it was more difficult to get them to spend more of their already constrained funds on energy efficiency and conservation. For residential customers, concerns about the impact on their employment from the economic challenges the country was facing, together with the end of the federal Home Renovation Tax Credit, had reduced customer activity in this program area. Moreover, uncertainty about the direction of the provincial government resulting from the changes in the Liberal and NDP leaderships also negatively impacted customer focus on EEC by increasing customer uncertainty about the longevity of government programs such as LiveSmart BC.

Second, relatively low gas prices not only made it harder to get customers' attention focused on energy efficiency and conservation, but was also a significant factor in the slightly negative TRC. The TRC is calculated based on avoided cost of gas resulting from undertaking EEC activity, divided by the cost of undertaking that activity. The avoided cost of gas used to calculate the results of the EEC activity presented in the 2009 EEC Annual Report averaged $13/GJ over the period 2009 to 2040; the 2010 results were based on an average cost of gas of $10.61/GJ over the period 2010 to 2041. Using an avoided cost of $13/GJ, the conventional portfolio returns a TRC result of 1.3, while the combined conventional and innovative technology portfolios return a TRC result of 1.2. This illustrates the challenge of using a market-based avoided cost to analyze the value associated with a utility's DSM activity and reflects a very narrow view of the benefits that accrue from that activity. The Companies' next submission for approval of future EEC activity in the 2012-2013 Revenue Requirements Application intends to address this issue, and should result in calculations of the benefits of future portfolios of EEC activity showing positive results.

With the current climate of low natural gas prices, the price of natural gas cannot be considered a driver of energy efficiency upgrades to any great extent, except in those customers with very high gas consumption or where natural gas is a significant input into some business process. Although the current price of gas can make it a challenge to find cost effective energy saving measures to incent, it reinforces the need for energy efficiency programs in order to achieve the government's energy and climate change objectives. With low natural gas prices, some customers are not motivated to save without utility encouragement. Energy Efficiency and Conservation programs then become necessary to drive long term market transformation towards improved efficiency.

Third, the number of activities to which the Companies do not attribute energy savings, but that are important enablers of energy efficiency activity were stepped up considerably in 2010.[7] For these activities, the Companies include the costs of undertaking them with no accompanying energy savings. For instance, expenditures on Conservation Education and Outreach programs more than doubled in 2010, from approximately $600,000 in 2009 to approximately $1.6 million in 2010. Other enabling portfolio level costs also grew from about $1.56 million in 2009 to $3.2 million in 2010. The Companies will be reaping the benefits of some of these enabling activities, such as the implementation of the DSM Tracking System, for years to come.

Despite these three limiting factors, the Companies are pleased with the results from the year's activities, as these results comply with program principles and meet most of the requirements for adequacy in the DSM Regulation.

2.3 TRC Result for Innovative Technologies

In Orders G-141-09 and G-140-09 regarding the Negotiated Settlement Agreements for the TGI and TGVI 2010-2011 Revenue Requirements respectively, the Commission directed that:

> *"…Innovative Technology Programs will be managed by TGI {TGVI} as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more."*

In accordance with this direction, the overall TRC result for the Innovative Technology program area, presented in Table 2-4, shows a positive result of 1.2. This is largely due to the inclusion of avoided high cost diesel purchases arising from NGV activity in the Innovative Technologies program area. This program area is discussed in more detail in Section 10.

7 These activities are further described in the "Enabling" and "Conservation Education and Outreach" sections of this Report.

Table 2-4: Innovative Technology Overall Program Portfolio Results

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	5,816	5	5,821	(162,911)	(726,396)	1.3
FEVI	143	0	143	1,683	19,845	0.3
Total	**5,959**	**5**	**5,964**	**(161,228)**	**(706,551)**	**1.2**

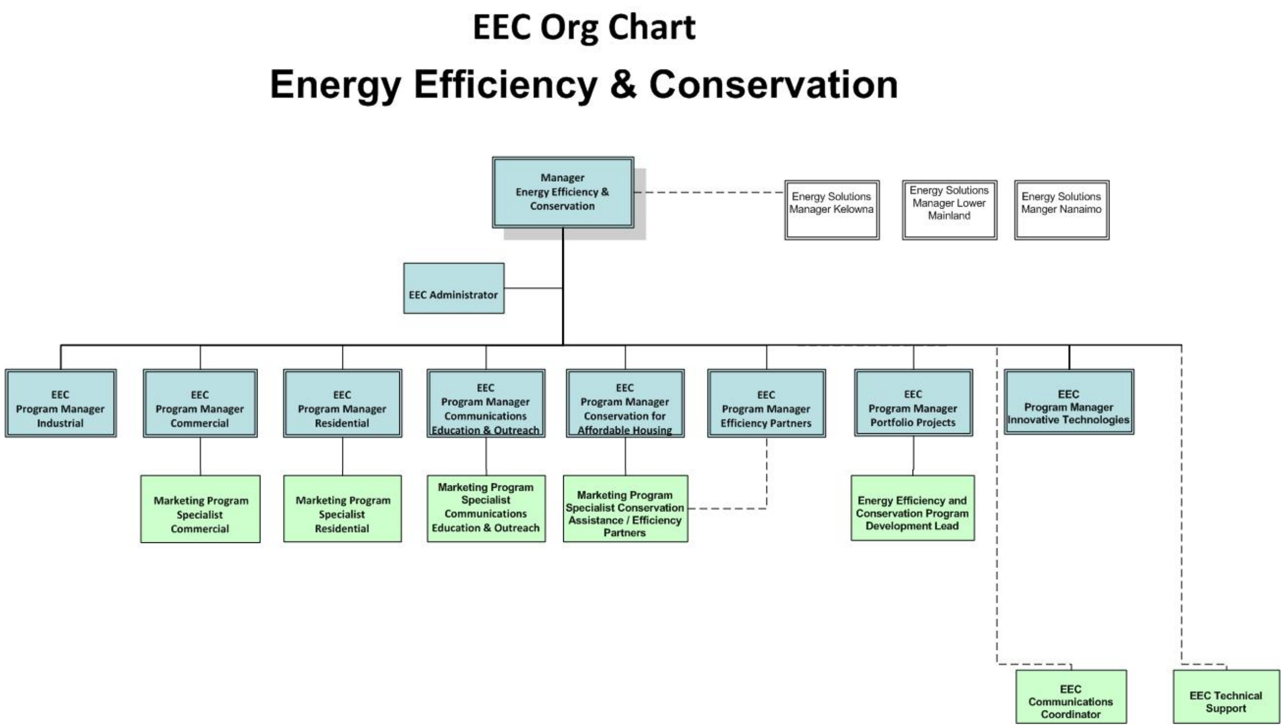
2.4 2010 EEC Activity – EEC Team Structure

The Companies' EEC activities in 2010 built upon the groundwork laid in 2009. In 2010, the Companies moved closer to enjoying a full year of EEC activity; however, it should be stated that a lack of human resources to design and deliver all the EEC initiatives identified by the EEC team as viable activities for the Company is hampering our ability to deliver all potential EEC programs. For instance, there are a number of potential program opportunities, especially in the commercial program area, that existing program staff do not have the time to address and develop. The Companies plan to address this shortage of human resources, which will be implemented in the second quarter of 2011.

However, responding to approvals of EEC funding granted in Orders G-141-09 and G-140-09 for innovative technologies and for interruptible industrial customers, the Companies have added dedicated program managers for these specific program areas, and these human assets were in place by the end of Q2 2010. In addition to the innovative technologies and industrial program managers, the Companies also added three EEC energy solutions managers in the Lower Mainland, Interior, and Vancouver Island service areas with the intent of providing more one-on-one support to commercial customers to encourage them to participate in commercial programs. More information about the activities of these energy solutions mangers can be found in Section 11.

The Companies' expenditures on labour for EEC activities in 2010 were $1.6 million. The Companies' current organization chart for the group primarily responsible for EEC activities is presented in Figure 2-1 below:

Figure 2-1: FEI/FEVI 2010 EEC Organizational Chart



2.5 2010 EEC Activity – Program Area Funding Transfers

FEI has approval for a total of approximately $26 million for EEC activities and programs in 2010. This is outlined in the table below.

Table 2-5: FEI 2010 Approved EEC Expenditures vs Actual EEC Expenditures

FEI - Program Areas	2010 Approved Expenditures ($000's)	2010 Actual Expenditures ($000's)	Variance ($000's)
Conventional EEC Activity	$23,510	$9,959	-$13,551
Innovative Technologies Activity	$2,334	$5,821	$3,487

While FEI under spent quite significantly compared to approved levels in the conventional EEC portfolio, there was more invested in innovative technologies than the Companies had put forward in the 2010-2011 Revenue Requirements Application (“RRA”). In 2010, FEI transferred $3.487 million from the conventional EEC program area to the innovative technologies program area to cover this additional investment. This transfer applies to FEI only. Such transfer is consistent with Commission Order No. G-36-09, which allows:

"…any inter and intra Program Area Initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives and measures as the case may be."

There is no impact to the transferor program area from the transfer to innovative technologies as conventional EEC activity was under spent compared to approved levels. However, there is a positive impact to the transferee program area in that the funding transfer allowed an expansion of the innovative technology program area. The detailed rationale for this transfer is described in Section 10.

As indicated in the 2010-2011 RRA, we have a true-up mechanism in place so only actual spend on EEC activities are charged to the EEC deferral account and ultimately get reflected in future delivery rates. The deferral account captures differences between approved budget and actual expenditures. In the upcoming RRA, to be filed with the Commission in May 2011, the Companies will be reviewing the EEC deferral account and may propose changes to the mechanism to address variances that may arise under multiyear RRAs.

2.6 2011 Planned Activities

Tables 2-6, 2-7 and 2-8 below show forecasted results for currently planned 2011 activity. More detail about currently planned 2011 EEC activity and associated expenditures can be found in the section of the report that deals with each individual program area. As it is fairly early in 2011, activity will grow and change over the course of the year as programs are modified to optimize participation and energy savings, and as additional opportunities present themselves to the Companies. The information presented below should be considered preliminary in nature.

Table 2-6: 2011 Overall EEC Program Portfolio Results

Utility	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	11,697	11,377	23,074	(3,606)	702,719	1.1
FEVI	1,595	2,230	3,825	24,892	199,777	0.8
Total	**13,292**	**13,607**	**26,899**	**21,286**	**902,496**	**1.1**

Table 2-7: 2011 Overall EEC Program Area Portfolio Results

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
Residential Programs	**1,710**	**825**	**21,288**	**187,402**	**0.8**
FEI	1,373	689	17,030	149,446	0.8
FEVI	337	136	4,258	37,956	0.8
Commercial Programs	**3,092**	**172**	**133,090**	**1,144,831**	**1.2**
FEI	2,701	138	117,077	1,021,668	1.2
FEVI	391	34	16,013	123,163	1.1
Joint Initiatives	**2,677**	**605**	**87,916**	**901,539**	**0.9**
FEI	2,428	514	79,180	814,827	0.9
FEVI	249	91	8,736	86,712	0.9
Conservation for Affordable Housing	**1,462**	**1,109**	**13,519**	**105,500**	**0.7**
FEI	1,170	888	10,816	84,514	0.7
FEVI	292	221	2,703	20,986	0.7
Innovative Technology	**3,931**	**124**	**(225,928)**	**(1,349,901)**	**1.8**
FEI	3,926	114	(225,989)	(1,350,618)	1.8
FEVI	5	10	61	717	0.2
High Carbon Fuel Switching	**420**	**104**	**(8,600)**	**(86,875)**	**1.6**
FEI	100	21	(1,720)	(17,116)	1.7
FEVI	320	83	(6,880)	(69,759)	1.8
Conservation Education and Outreach		**3,538**			
FEI		2,890			
FEVI		648			
Portfolio Level Activities		**7,131**			
FEI		6,123			
FEVI		1,008			
Total	**13,292**	**13,607**	**21,286**	**902,496**	**1.1**

Table 2-8: 2011 Overall Program Portfolio Results – Conventional EEC Portfolio

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	7,772	11,262	19,034	222,383	2,053,338	0.7
FEVI	1,590	2,220	3,810	24,831	199,060	0.8
Total	**9,362**	**13,482**	**22,844**	**247,214**	**2,252,398**	**0.7**

In the Companies' next request for EEC funding authorization in the next RRA, it is the intent of the Companies to pursue a methodology for cost-benefit analysis that should see the Companies' EEC portfolio TRC ratio increase to over 1.0. The relatively low cost of gas being used by the Companies to calculate the TRC ratio is negatively affecting TRC results.

Table 2-9: 2011 Innovative Technology Overall Program Portfolio Results

Utility	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	3,926	114	4,040	(225,989)	(1,350,618)	1.8
FEVI	5	10	15	61	718	0.2
Total	**3,931**	**124**	**4,055**	**(225,928)**	**(1,349,900)**	**1.8**

As with 2010 activity, the 2011 Innovative Technologies portfolio includes funding for NGVs.

2.7 Compliance with Adequacy Requirements in the Demand Side Management Regulation

The DSM regulation (attached as Appendix C) has the following requirements for a utility's portfolio of EEC activity to be considered adequate:

"A public utility's plan portfolio is adequate for the purposes of Section 44.1 (8) c of the Act only if the plan portfolio includes all the following:

a) A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
b) If the plan portfolio is introduced on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
c) An education program for students enrolled in schools in the public utility's service area;
d) If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area."

The Companies believe that by the end of 2011, when the currently approved funding envelope ends, they will have met all the requirements for adequacy. There are a number of programs for low income customers, which are discussed in their own section (see Section 6). A number of the commercial programs are utilized by owners of rental buildings: the Efficient Boiler program, the Light Commercial Boiler program, and the Efficient Commercial Water Heaters program. The Fireplace Timer Pilot program is also available to rental buildings. More information about these commercial programs available to rental buildings can be found in Section 4. Similarly, all residential programs are available to rental properties. A Multi Unit Residential Building pilot program with the City of Vancouver is underway and if successful it will be expanded across the

Companies' service territories, and would include rental buildings. In terms of education programs, the Companies fund the following initiatives for K-12 students:

- BC Green Games;
- BC Lions Energy Champion School Assembly Presentations;
- Beyond Recycling;
- Destination Conservation;
- BC Sustainable Energy Association Climate Change Showdown; and
- Environmental Mind Grind.

More information about these initiatives can be found in Section 8. The Companies have an initiative for post-secondary student engagement under development and anticipate having a project for post-secondary students in market in September 2011. Thus the requirements in the DSM Regulation for adequacy will be met.

2.8 Conclusion

Although the Companies did not reach the approved levels of expenditure for 2010, significant progress was made toward laying a strong foundation for future growth in EEC activity. The overall portfolio TRC ratio, including both conventional and innovative technologies EEC activity, was 1.1 and therefore was compliant with Commission Order No. G-36-09. The Companies have identified a need to add human resources in order to deliver energy efficiency and conservation programs to approved expenditure levels to our customers, and we look forward to adding those resources in 2011. The Companies' EEC activity will meet all the adequacy requirements in the DSM Regulation by the end of the current funding approval period in 2011.

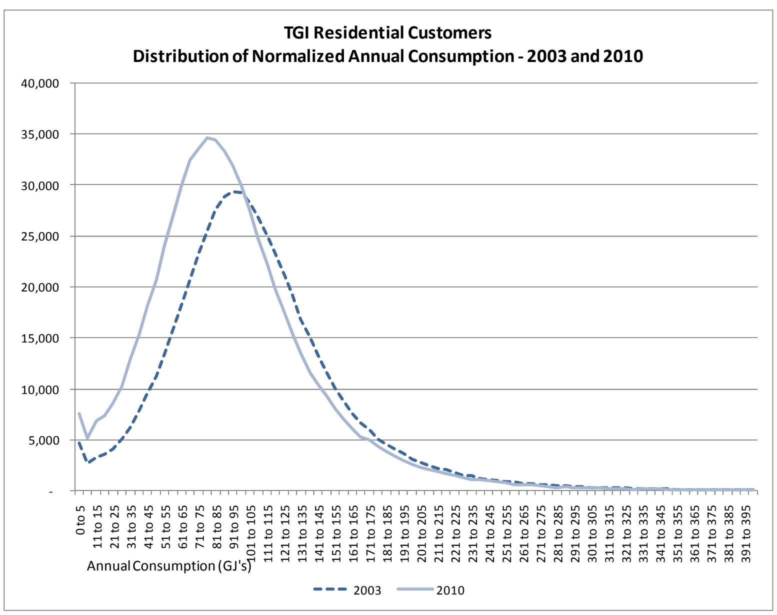
3 RESIDENTIAL ENERGY EFFICIENCY PROGRAM AREA

3.1 Overview

The Residential Energy Efficiency Program Area provides value to customers by encouraging households to reduce their overall consumption of natural gas and manage their energy bills. Residential programs serve over 850,000 households in the FEI and FEVI territories for both retrofit and new construction applications. For EEC purposes, these customers include end-use customers living in a residential single-family home, row house, townhouse or mobile home. Programs for Multifamily Dwellings are included in the Commercial Energy Efficiency Program Area under development for 2011 (please refer to Section 4).

Residential programs, in combination with the Companies' education and outreach activities, are an important component in driving the culture of conservation in the province. A recent survey[8] of BC customers emphasizes the utility's role in providing information on conservation. Three in five (62 percent) respondents would look for information on energy efficiency programs on the Internet, followed by half (50 percent) asking their utility, and about a third asking the provincial government (38 percent) and the federal government (32 percent). The ultimate goal of residential programs is to shift the overall natural gas consumption curve whereby a greater proportion of customers use natural gas more efficiently, as presented in Figure 3-1.

Figure 3-1: FEI Residential Customers Distribution of Normalized Annual Consumption – 2003 and 2010



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[8] Residential Retrofit Market Evaluation by Angus Reid Strategies, commissioned by the Companies in January 2010.

The Companies' EEC application highlighted the findings in the 2006 CPR in that 70 percent of the Achievable Potential savings were associated with the residential sector. To that end, in Commission Order No. G-36-09 on the Companies' EEC application, the Companies received approval for residential program funding of $9.3 million over the 2008-2010 period. Furthermore, in Order No. G-141-09 approving FEI's 2010-2011 Negotiated Settlement Agreement, the Commission approved FEI's request for an extension of residential program funding to 2011 in the amount of $3.275 million. Similarly, for FEVI, in Order No. G-140-09, the request for EEC funding of $0.3 million for 2011 residential programs was approved. This funding enabled the Companies to further their EEC goals in delivering programs that enable customers to implement measures to reduce their natural gas consumption while supporting the government's GHG emissions reduction strategy.

Sections 3.1 through Section 3.3 outline the Residential Energy Efficiency Program Area goals, the program portfolio in the market to achieve these goals, 2010 program results, and the outlook for 2011. Section 3.4 provides individual program details including individual program goals, 2010 results, and the outlook for 2011.

3.1.1 RESIDENTIAL PROGRAM GOALS

The Residential Energy Efficiency Program Area encourages households to reduce their overall consumption of natural gas and helps to manage their energy bills. Residential programs deliver value through their focus on the following objectives:

- Educate customers about the advantages of energy efficiency and promote the benefits of the culture of conservation;
- Prepare and ultimately transform the market by facilitating the adoption of new energy efficient technologies through incentives and support of government regulations;
- Upgrade low efficiency systems to high efficiency systems in order to capture energy savings associated with reducing the overall consumption of natural gas;
- Support government policy, especially in relation to efficient building strategies[9] and GHG emissions reduction, through incentives and education to customers and other industry stakeholders;
- Assist trades in understanding technical requirements or other barriers associated with new product introductions and support their effective installation;
- Engage manufacturers in developing, producing, and distributing energy efficient equipment through technology support and promotional opportunities to the Companies' customer base; and
- Develop a greater awareness of the non-energy benefits of efficiency systems such as improved comfort, health, safety, property value, and reduced insurance claims. To this

[9] BC Energy Efficient Buildings Strategy: More Action, Less Energy. BC Ministry of Energy and Mines Publication, 2008.

end, promote the concept of "House as a System" or a "Whole Home" approach to efficiency.

- In support of the objectives listed above, the Companies will deliver the following:
- Cost-effective programs that optimize the proportion of incentives over administration and marketing costs while ensuring the overall EEC portfolio is above 1.0; and
- Program evaluation that confirms savings claims, provides participant feedback, and guides future program design.

3.2 2010 Residential Energy Efficiency Program Area Results

Residential programs have encouraged residential customers to reduce their annual natural gas consumption by 62,036 GJs/yr, resulting in nearly 607,000 GJs of savings over the lifetime of the measures and a significant contribution to the reduction of GHG emissions in the province. The FEI TRC was 1.0 while FEVI's equalled 0.7, likely due to lower participant numbers while incurring program deployment costs. Program area objectives were achieved through a $3.2 million investment in incentives, administration, and program communications. Of this investment, 93 percent was incentives that directly offset the customer's cost of appliance upgrade or furnace service. The table below provides program details for incentive and non-incentive expenditures, energy savings, and TRC results.

Table 3-1: 2010 Residential Energy Efficiency Program Area Results

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
2010 Residential Program Activity								
ENERGY STAR® Heating System Upgrade 2010 - FEU + LivesmartBC	2,385	86	2,471	578,285	19,145	597,430	1.1	1.0
Furnace Service "TLC" - 2010	432	79	511	No Direct Savings				
Domestic Hot Water Heaters	67	14	81	1,990	269	2,259	0.3	0.2
EnerChoice Fireplace - 2010	56	15	71	5,746	1,415	7,161	1.0	1.1
Non program specific expenses	74	35	108					
Total	**3,014**	**228**	**3,242**	**586,021**	**20,829**	**606,850**	**1.0**	**0.7**

The 2010 Residential Energy Efficiency Program Area portfolio achieved its EEC program objectives by investing over $3.2 million in energy efficiency projects. In addition to capturing 607,000 GJs of savings over the lifetime of these installed measures, program promotion furthered the culture of conservation by contributing to the market transformation of space and water heating systems through incentives and support for the introduction of government regulations, and promoting natural gas efficiency with contractors, manufacturers, and retailers as outlined below.

3.2.1 CONTRIBUTION TO MARKET TRANSFORMATION

The Companies' contribution to market transformation of space and water heating systems is substantial for both space and water heating as outlined below:

The Companies have maintained ENERGY STAR® Heating System Upgrade programs in the market since 1996, of which the most recent iteration was launched September 1, 2008 in the FEI service territory and April 16, 2009 in the FEVI service territory. This highly successful program, in collaboration with LiveSmart BC, provided incentives for over 17,000 furnaces, a contribution of $4.4 million in incentives and over 1.1 million GJs of energy savings over the lifetime of these systems. This program ended December 31, 2009 to coincide with provincial and federal government regulations requiring that all furnaces sold in Canada meet a minimum standard of 90 percent efficiency.[10] The Companies' significant outreach to consumers, trades, and manufacturers helped facilitate the industry's transition to the new regulation. Please note that although the program ended December 31, 2009, final participation counts were not available at the time of writing the 2009 report. Only applications processed in 2010 are included in the 2010 program energy savings.

The Companies are taking an active role in driving a national Domestic Hot Water ("DHW") market transformation strategy through the 0.8 EF water heater technology pilot outlined in Section 3.4.3.2. An initial step in this strategy was the 2010 launch of the 0.62 EF Efficient Storage Tank Water Heater Program, whose initial objective was compliance engagement for the introduction of provincial gas water heater efficiency act regulations that are the highest standard in Canada.[11] The program was effective in driving some manufacturers to comply with these new regulations, although it will take some time for 100 percent market adoption.

In order to promote energy efficient fireplaces that generate heat rather than being just decorative, the Companies are actively promoting EnerChoice fireplaces in partnership with the western chapter of the Hearth, Patio and Barbecue Association of Canada ("HPBAC") and are among the few North American utilities to have an EnerChoice program. Industry feedback suggests that manufacturers are more conscious of fireplace efficiency through the EnerChoice program and energy efficiency messaging that creates consumer demand.

3.2.2 COLLABORATING WITH INDUSTRY TO PROMOTE THE CULTURE OF CONSERVATION

Industry partnerships with contractors, manufacturers, retailers, and associations are key to driving program participation and fostering the culture of conservation as outlined below:

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[10] Please refer to Appendix D for a copy of the MEMPR Enforcement Bulletin 09-03. BC Efficiency Act Standards: Gas and Propane-Fired Furnaces.

[11] Please refer to Appendix D for a copy of the MEMPR Enforcement Bulletin 09-05. BC Efficiency Act Standards: *Gas and Propane-Fired Water Heaters*.

Engaging natural gas contractors is a critical component to the success of residential programs. Program evaluation studies[12] suggest that 26 percent of program participants are made aware of programs through contractor communications, which is second only to the 29 percent of participants made aware through the Companies' bill inserts. Program kits are mailed to all contractors in the BC Safety Authority ("BCSA") database. The Companies are furthering their relationship with the trades through their partner program outlined in Section 11.2.2.

Collaboration with manufacturers of energy efficient technologies is also key to program success and market transformation. In 2009, furnace manufacturers were required to meet 0.90 AFUE federal and provincial Efficiency Act standards. In 2010, DHW manufacturers were required to meet 0.62 EF provincial Efficiency Act standards for gas water heaters. The Companies' water tank program drew attention to compliancy by providing a joint incentive to customers and contractors. Anecdotal evidence and rejected applications indicate there are still a large number of non-compliant tanks being sold. The current water heater rebate offer will, therefore, remain in market for 2011 to support the introduction of the 0.67 EF ENERGY STAR® water heaters and new technologies.

The Companies also initiated partnerships with big box retailers that have extensive marketing budgets and the ability to educate customers in a mainstream retail setting. In 2011, the Companies will further strengthen partnerships with retailers and dealer networks to promote energy efficient products and services.

Another key success of 2010 was furthering the Companies partnerships with industry stakeholders. A greater number of programs are being integrated with electric utilities and provincial and municipal governments (please refer to Section 7 Joint Initiatives). The Companies have also forged strong partnerships with industry associations such as the BCSA, Thermal Efficiency Contractors Association ("TECA"), HPBAC and others. Partnerships with associations are fundamental to the development of the contractor's network and key to ensuring the safe and effective installation of high efficiency equipment.

3.2.3 HIGHLIGHTS OF 2010 RESIDENTIAL ENERGY EFFICIENCY PROGRAM AREA

A summary of highlights from 2010 residential programs include the following achievements:

- Investing over $3.2 million in energy efficiency initiatives resulting in 607,000 GJs of savings over the lifetime of the measures;
- Engaging over 31,000 customers in 2010 programs targeting residential customers;
- Collaborating with industry partners including government, electric utilities, contractors, manufacturers, and retailers; and
- Establishing outsourced administration for mass-market residential programs by employing Consumer Response Marketing Ltd. ("CRM"), a BC-based company. With

[12] 2005-2007 Heating System Upgrade Program: Evaluation Results. Sampson Research.

CRM's cost-effective expertise in providing rebate fulfillment and call centre support, the EEC team were able to focus on program delivery.

With this foundation now in place, the Companies will continue to deliver value to residential customers through the 2011 Residential Energy Efficiency Program Area.

3.3 2011 Residential Energy Efficiency Program Area Outlook

The Companies will expand the 2011 residential program offering in support of the EEC program objectives outlined previously by continuing many of the 2010 programs as well as introducing new programs, most notably a new construction program as outlined in Table 3-2. Expenditures from new programs are not included as program design is still in progress. As a result of the introduction of new programs, the Companies expect to spend more than the $2.5 million indicated in Table 3-2.

Table 3-2: 2011 Residential Energy Efficiency Program Area Outlook

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
2011 Programs in Market								
Furnace Service "TLC" - 2011	488	118	606	No Direct Savings				
Domestic Hot Water Heaters	567	142	709	47,415	12,043	59,458	0.6	0.6
EnerChoice Fireplace - 2011	693	173	866	102,031	25,963	127,994	2.2	2.3
2011 - 2012 Residential Programs Under Development								
Simple Home Efficiency Measures	Under Development							
Domestic Hot Water - 0.8EF- PILOT	Under Development							
Furnace - "Scrap-It" Program	Under Development For 2012							
EnerGuide 80 - New Construction	Under Development							
EnerGuide 80 - Townhome - PILOT	154		154					
Non program specific expenses	160	40	200					
Total	2,062	473	2,535	149,446	38,006	187,452	N/A	N/A

Please note that all 2011 programs are undergoing further economic analysis for the validation of savings claims and cost benefit tests. All numbers are estimates that will be validated in the coming months.

3.3.1 CHALLENGES IN DEVELOPING RESIDENTIAL PROGRAMS FOR NATURAL GAS EFFICIENCY

One of the major obstacles in the deployment of residential programs is in identifying measures that pass the traditional TRC cost benefit test. This constraint limits the investment utilities can make in market transformation, or, in the case of new construction programs, limits the role utilities can take in supporting the introduction of new efficiency codes and standards.

Ultimately, traditional DSM rules reduce our ability to support government policy to meet GHG emission reduction targets and limit our ability to invest in programs that serve our customers in managing their energy bills.

There are a number of factors that limit residential program development under traditional DSM environments, some of which are outlined below:

- The low cost of natural gas combined with lower than average consumption in BC's coastal climate limits program options;
- In traditional DSM environments, rebate programs cannot be in market for measures that are regulated. As a prime example, the Companies believe a furnace replacement program is fundamental to driving savings in space heating since heating systems represent 63% of the residential end use of natural gas. The 2008 REUS study suggests that only 16% of our customers have high efficiency furnaces. A furnace replacement program therefore represents an enormous opportunity to save natural gas and reduce GHG emissions;
- With the introduction of regulations for higher efficiency standards, the incremental savings that can be claimed over base technology is diminishing;
- Since new technologies are more expensive than base models, the TRC model hampers market transformation and innovation. Furthermore, when a new product is introduced, there are limited quantities of that product available for mass consumption. This results in further lowering the TRC since initial participation rates are low and the Companies incur significant program costs for program setup and promotion; and
- It will take some time to quantify the non-energy benefits associated with efficiency, such as improved comfort, health, safety, property value, and reduced insurance claims.

All of these examples demonstrate the challenges gas utilities face in driving market transformation and energy savings in the residential sector. The Companies are exploring other possibilities for ensuring new programs are cost-effective and provide value to customers. Discussions with government, other utilities, and regulators are underway to determine a collaborative solution that best meets the GHG emissions reduction targets of the province.

3.3.2 2011 OUTLOOK FOR RESIDENTIAL ENERGY EFFICIENCY PROGRAMS

The 2011, the Residential Energy Efficiency Program Area portfolio will continue to create value for residential customers and the industry, while furthering government policy on climate action. A summary of highlights for 2011 residential program planning include the following:

- Invest over $2.5 million in residential programs resulting in over 200,000 GJs saved over the lifetime of the measures;
- Engage over 30,000 customers in energy efficiency programs and all of our customers in conservation messaging;

- Introduce a new construction program to support new building codes and standards and the installation of efficient appliances; and
- Collaborate with industry partners including government, electric utilities, contractors, manufacturers, and retailers.

With the foundation now in place to introduce programs to the residential sector, the Companies will continue to deliver value to residential customers in 2011 and beyond.

3.4 Residential Program Details

Program descriptions for each of the Companies' residential energy efficiency offerings are outlined in the following section. Program details include background information, goals, 2010 results, future outlook, and an overall summary. Table 3-3 provides an overview of residential programs indicating which programs were completed in 2010, which programs remain active moving into 2011, and which programs are currently under development.

Table 3-3: Residential Energy Efficiency Program Overview

Program	Utility		Description	TRC	
	FEI	FEVI		FEI	FEVI
Completed Programs					
ENERGY STAR® Heating System Upgrade - 2009	X	X	$250 incentive for upgrading heating system to Energy Star rated appliance - FEU and LiveSmart BC Total	1.1	1.0
Furnace Service Campaign - "Give your furnace some TLC" - 2010	X	X	Educate the market about the importance of appliance maintenance and create opportunities to upgrade appliances for efficiency	No Direct Savings	
Active Programs				**Projected TRC**	
Domestic Hot Water 0.62 EF & ENERGY STAR® Tanks	X	X	$50 consumer incentive and $50 contractor's incentive to educate customersabout proactive replacement of efficient water heaters. Additional tiers to be added in Q2	0.6	0.6
EnerChoice Fireplace	X	X	$150 (to $300) consumer incentive for EnerChoice fireplaces. Program revised in Q2	2.2	2.3
Furnace Service Campaign - "Give your furnace some TLC" - 2011	X	X	Educate the market about the importance of appliance maintenance and create opportunities to upgrade appliances for efficiency	No Direct Savings	
Programs in Development					
Simple Home Efficiency Measures	X	X	Discount or giveaway program for low-cost measures that reduce heat and hot water energy consumption	Under Development	
Domestc Hot Water - 0.8 EF - PILOT	X		Assess 0.80 EF water heating technologies in support of 2020 hot water efficiency federal and provincial regulation	Under Development	
Furnace - "Scrap-It" Program	X	X	Re-educate market about high efficiency furnaces and urge customers to upgrade early	Under Development	
EnerGuide 80 - New Construction Program - PILOT	X	X	Educate builders about new proposed BC Building Codes and provide incentives for adoption. Educate consumers about the benefits of purchasing energy efficient homes	Under Development	
"84 Developments" EGH80 Townhome - PILOT	X		Work with builder to understand prescriptive and performance path to reaching EGH80 in townhomes. Create case study for other builders	1.4	

3.4.1 COMPLETED PROGRAMS

3.4.1.1 ENERGY STAR® Heating System Upgrade Program

3.4.1.1.1 Program Overview

2008-2009 ENERGY STAR® Heating System Upgrade Program	
Target Audience	Residential Retrofit Customers
Duration	FEI: Sep 1, 2008 through Dec 31, 2009 FEVI: Apr 16, 2009 through Dec 31, 2009 Note: Because the application deadline was March 31, 2010, final program numbers were not available for the 2009 EEC report and savings from applications processed in 2010 are included in the 2010 portfolio.
Incentive	$250 rebate per heating system upgrade
Partner	LiveSmart BC / Ministry of Energy and Mines
Overview	
Background	The primary program objective was to reap the energy savings associated with upgrading low or mid-efficiency heating systems to ENERGY STAR®. The Companies have maintained ENERGY STAR® Heating Upgrade programs in the market since 1996. These programs were initiated to benefit customers by saving them energy and to participate in transforming the furnace market. The most recent iteration was launched September 1, 2008 in the FEI service territory and April 16, 2009 in the FEVI service territory. In addition to energy savings, the program focused on preparing the market for January 1, 2010 changes to the BC Energy Efficiency Act Standards for gas furnaces outlined in the Ministry of Energy Mines and Petroleum Resources (“MEMPR”) Enforcement Bulletin 09-03[13]. The regulated energy efficiency standard for these products is an Annual Fuel Utilization Efficiency (“AFUE”) equal to or greater than 90%. These regulations took effect for new residential construction on January 1, 2008 and for replacement furnaces in existing dwellings on December 31, 2009. The BC provincial regulation changes align with Natural Resources Canada (“NRCan”) regulations for new and existing buildings across Canada. The Companies’ significant outreach to consumers, trades, and manufacturers helped facilitate the industry’s transition to the new regulation. In September 2008, the Companies partnered with the LiveSmart BC Residential Retrofit Incentive Initiative in order to extend market reach and program awareness and initiate collaborations between government and utility partners. Please refer to Section 7.4.2.1 for further information about the LiveSmart BC partnership.

[13] Please refer to Appendix D for a copy of the MEMPR Enforcement Bulletin 09-03.

Goals	• Upgrade a minimum of 8,180 heating systems. • Prepare market for adoption of ENERGY STAR® provincial furnace regulations for retrofit market, January 1, 2010. • Educate consumers about the advantages of energy efficient furnaces and boilers and provide an incentive that promotes a proactive replacement decision. • Educate the trades about upcoming regulations. • Engage manufacturers by distributing coupons for ENERGY STAR® furnaces and boilers and providing funds for co-marketing opportunities.
Description	In order to educate customers and the trades about the benefits of ENERGY STAR® heating system upgrades, the Companies offered a $250 bill credit to partially offset the estimated $850 incremental cost of purchasing ENERGY STAR® furnaces or boilers over mid-efficiency models. In addition to the $250 incentive, from September to December 2008 and 2009, furnace and boiler manufacturers provided coupons for discounts and extended warranties for ENERGY STAR® heating systems.
Implementation	
Administration	Accenture Utilities Business Process Outsourcing Services("ABSU"), a subsidiary of Accenture Inc., through a subcontracting arrangement with CustomerWorks LP, processed the bill credit rebate process for the Companies' applications. The Ministry of Energy processed LiveSmart BC applications. De-duplication was performed to ensure customers were only awarded a single $250 rebate.
Communications	Promotions included website prominence, bill inserts, advertisements in community newspapers and trade publications, and events. In the fall of 2008 and 2009, manufacturers provided coupons for additional savings on furnace replacements.
Evaluation Strategy	An extensive evaluation of natural gas consumption after installation of an ENERGY STAR® furnace or boiler on 2005-2007 program participants confirmed energy savings estimates of over 11 GJs per participant (Sampson and Associates). The study provided in-depth feedback for future program development.

3.4.1.1.2 2008-2009 ENERGY STAR® Heating System Upgrade Program Results

Table 3-4: 2010 Program Results

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
2009 Application Processing								
The Companies	FEI	4,391	1,098	101	27,882	293,682	43%	1.1
	FEVI	83	21	14	527	5,519	43%	0.9
Live-Smart BC	FEI	3,391	848	7	21,532	226,799	43%	1.2
	FEVI	65	16	-	413	4,322	43%	1.2
2010 Application Processing								
The Companies	FEI	3,849	962	51	24,346	238,325	43%	1.0
	FEVI	106	27	11	671	6,810	43%	0.9
Live-Smart BC - *	FEI	5,489	1,372	-	34,729	339,960	43%	1.1
	FEVI	192	48	-	1,215	12,335	43%	0.9
Total Program Activity								
Total	FEI	**17,120**	**4,280**	**159**	**108,489**	**1,098,766**	**43%**	**1.1**
	FEVI	**446**	**112**	**25**	**2,826**	**28,986**	**43%**	**1.0**
Total		**17,566**	**4,392**	**184**	**111,315**	**1,127,752**	**43%**	**1.1**
LiveSmart BC Participant Counts based on January 25, 2011 invoice and estimation of final program countsthat are forthcoming from the Minstry of Energy.								

This program was extremely successful with double the anticipated program participation of 8,180 participants outlined in the 2007 EEC Application. Through this program over $4.4 million in incentives were distributed to customers across the province with downstream benefits of revenues, job creation, and installation experience to contractors, dealers, and manufacturers. Table 3-4 provides performance metrics for 2009 and 2010 including number of participants, incentives to non-incentives spending, net annual energy savings, and the savings over the lifetime of the measure. The free rider rate suggests that 43 percent of participants may have upgraded their appliance without the incentive, so this proportion of participants has been backed out of the energy savings. This free rider rate was obtained from consumer and contractor feedback as presented in the 2005-2007 Furnace Program Evaluation (Please refer to Appendix D in the 2009 EEC report).

The positive TRC indicates that despite a relatively high free rider rate there remains substantial energy savings within a cost-effective program. TRC results were 1.1 for FEI and 1.0 for FEVI. The FEVI TRC is slightly lower due to lower participant numbers as the program was introduced over seven months later than the FEI program. Also, natural gas service was first introduced to Vancouver Island in 1990, so the FEVI opportunity for furnace replacement is lower because furnace stock is newer.

In addition to the Companies' rebate, other key drivers that positively influenced furnace replacement during this timeframe were provincial incentives through LiveSmart BC, federal incentives through the NRCan EcoAction program, and the Home Renovation Tax Credit.

The 2008 REUS suggests that only 16 percent of the Companies' residential customers have high efficiency furnaces (90 percent AFUE and higher), 39 percent have mid-efficiency furnaces (78 - 85 percent AFUE), and 45 percent have standard efficiency furnaces (less than 78 percent AFUE). This indicates that 84 percent of the Companies' customers have either a need to upgrade their standard efficiency furnaces or have mid-efficiency furnaces that are close to the end of their useful lives. There is a substantial need for incentives or financing options that would help remove financial barriers for proactive furnace replacement and a huge opportunity for energy savings and GHG emissions reductions through such initiatives.

3.4.1.1.3 Overall Summary

The most recent iteration of the ENERGY STAR® Heating System Upgrade Program far surpassed its original program target and contributed to the replacement of over 17,500 heating systems. In addition, the program achieved its objective of preparing the market for the introduction of provincial and federal regulations requiring the installation of ENERGY STAR® furnaces. Broader market impacts are evident through the Companies' contribution of $4.4 million in funding for 17,500 heating system upgrades since September 2008. Downstream economic benefits to the economy are estimated to be $102 million[14] in consumer spending with a significant positive impact on employment in energy efficient upgrades. Energy savings impacts of 1.1 million GJs over the lifetime of these installations and the associated GHG emissions reduction impacts are significant. The partnership with the LiveSmart BC program represented about half the participants. Encouraging homeowners to take a whole home approach to renovations have resulted in even greater energy savings for our customers and GHG emissions reductions for the province.

3.4.1.2 "Give Your Furnace Some TLC" – Furnace Service Campaign

3.4.1.2.1 Program Overview

"GIVE YOUR FURNACE SOME TLC"- FURNACE SERVICE CAMPAIGN	
Target Audience	Residential Retrofit Customers
Duration	FEVI: Jan 15 - Oct 31, 2010 FEI: June 1- Oct 31, 2010

[14] $102 million consumer spending estimate based on 17,566 program participants multiplied by $5,800, which is the average heating system installation expenditure in the 2010 Switch 'N' Shrink program.

Incentive	$25 Grocery Gift Card
Partner	None
Overview	
Background	The primary objective of the furnace service campaign was to develop an offer that was relevant to a broad base of customers and engage them in energy efficiency dialogues with gas contractors. Customers were educated about the importance of annual furnace servicing while the long-term benefits of appliance efficiency and the cost savings associated with upgrading to high efficiency heating systems was promoted. In addition, the program reinforced the Companies' relationship with the trades, given that the promotion reminded customers to have their furnace serviced and contractors were able to identify furnaces/boilers needing replacement. The program was first piloted in FEVI where over 300 applications were received within eight weeks of launching the program, demonstrating that customers respond well to a $25 gift card incentive. Due to the success of the pilot, the Companies rolled out the program across the province in June 2010.
Description	The program offered a $25 grocery gift card to the Companies' residential customers who had their furnaces serviced by a qualified contractor within the program eligibility dates.
Goals	• Provide education and awareness about energy efficient appliances and their maintenance. • Engage customers and contractors in conversations about efficiency, safety, and the opportunity to upgrade existing mid-efficiency appliances to high efficiency appliances.
Implementation	
Administration	Consumer Response Marketing Ltd.
Communications	Promotions included website prominence, a June stand-alone bill insert, an August bill insert program listing, and handouts at summer and fall events. The program did not require a major advertising investment given that the trades promoted the campaign on our behalf.
Evaluation Strategy	A total of 375 telephone surveys were completed by customers who participated in the TLC Furnace Program. The survey reported high customer satisfaction with a large majority of participants being extremely satisfied with the outcome of their overall service visit Furthermore, it is important to note that the research company reported an unexpected willingness of applicants to complete the survey.

3.4.1.2.2 2010 Results

Table 3-5: 2010 "Give Your Furnace Some TLC"- Furnace Service Campaign Results

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	13,911	320	112	No Direct Savings			
FEVI	1,550	36	42				
TOTAL	15,461	357	154				

* Incentive expenditure accounts for a the fact that FEI gift cards received an 8% discount while the FEVI gift cards received a 6% discount.

The campaign was extremely successful with 15,500 participants and $357,000 in incentives distributed. It was even more successful in light of the fact that these program participation numbers were achieved without major advertising investment since the trades promoted the campaign on our behalf.

Although other utilities have claimed energy savings in the past, we were not able to find definitive evaluation studies that confirmed decreased consumption including past programs that were conducted by the Companies. Intuitively, a heating system that is well-maintained will run more smoothly and consume less energy. Program evaluation[15] determined that 4 percent of customers identified gas leaks and 15 percent of customers were advised to either upgrade or replace their appliance. This demonstrates that the goal of furnace replacements and supporting public safety were achieved.

3.4.1.2.3 2011 Performance Outlook

Table 3-6: 2011 "Give Your Furnace Some TLC" - Furnace Service Campaign Performance Forecast

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	16,000	368	120	No Direct Savings			
FEVI	4,000	92	26				
TOTAL	20,000	460	146				

The 2010 participant survey determined that the campaign in its current form had a high degree of customer satisfaction; however, there are a number of areas that will be improved for the 2011 campaign rollout to enable the Companies to drive even higher participation rates. In the

15 "TLC Furnace Servicing Study" A Participant Survey by TNS, commissioned by the Companies in November, 2010. Final report delivered January 18, 2011.

2011 iteration, communications with gas contractors will be improved and marketing materials will focus on the benefits of annual appliance maintenance. The addition of a fireplace servicing offer is under consideration.

3.4.1.2.4 Overall Summary

The "Give Your Furnace Some TLC" furnace service campaign's broad based appeal makes it a cornerstone program in engaging customers and contractors in conversations about natural gas efficiency, appliance safety, and the need to replace old heating systems with new high efficiency models. At this time, we are not capturing direct savings from this program; however, educating customers about the benefits of efficient equipment maintenance, while creating opportunities to further educate customers about energy saving behaviours and programs opens the door to future natural gas savings.

3.4.2 ACTIVE PROGRAMS

3.4.2.1 Energy Efficient Residential Hot Water Storage Tank Program

3.4.2.1.1 Program Overview

ENERGY EFFICIENT RESIDENTIAL HOT WATER STORAGE TANK PROGRAM	
Target Audience	Residential Retrofit Customers
Duration	FEI & FEVI: July 1, 2010 - Dec 31, 2011
Incentive	$50 rebate cheque for consumer $50 rebate cheque for contractor/dealer
Partners	Retailers (Rona, Sears) and manufacturers (Giant, A.O. Smith, Bradford-White)
Overview	
Background	A Domestic Hot Water ("DHW") strategy is a key component in the Companies' EEC program portfolio since water heating accounts for 21% of residential natural gas consumption. The CPR[16] states that DHW accounts for 21% of residential natural gas consumption and notes a 2% annual energy improvement as hot water systems are upgraded. Even greater savings will be realized as water heating appliances become more efficient. In 2010, the primary program objective was to educate the market about September 1, 2010 changes to the BC Energy Efficiency Act Standards for gas and propane fired water heaters outlined in MEMPR Information Bulletin 09-05[17]. BC provincial regulations require that all water tanks manufactured after September 1, 2010 have an efficiency rating ("EF") of at least 0.62 depending on tank size. The secondary program objective was to capture the energy savings associated with upgrading water heating systems. Additional program benefits include outreach to consumers,

[16] 2006 Terasen Gas Conservation Potential Review.
[17] Please refer to Appendix D for a copy of the MEMPR Enforcement Bulletin 09-05. BC Energy Efficiency Act Standards: *Gas and Propane-Fired Water Heaters.*

<table>
<tr><td></td><td>trades, distributors, big box and small retailers, and manufacturers. One program challenge is the fact that manufacturers do not label water heaters with efficiency ratings. Manufacturer engagement will be a key component of the program.

Based on estimates from the Canadian Institute of Plumbing and Heating (“CIPH”), approximately 120,000 hot water tanks are sold annually in BC. The market share for gas water heaters is in the range of 40-60%. According to water tank statistics from the 2008 REUS, 38% of water tanks were replaced over the past five years, which by calculation represents a 7.6% annual churn rate. Of those that were replaced, 83% were only done at the time of failure or imminent failure and 9% were undertaken for the purpose of increasing energy efficiency.</td></tr>
<tr><td>Description</td><td>The 2010 program included the following base offer that will remain in market for 2011.

A $50 consumer incentive drives public awareness about the importance of water tank efficiency, urges customers to not only replace their hot water tanks as an emergency purchase decision at the end of useful life but to be proactive prior to tank failure, and provides an opportunity to raise awareness about the importance of hot water conservation.

A $50 dealer incentive urges contractors and distributors to promote efficient water tanks. Since the large majority of purchase decisions are completed out of necessity due to tank failure, customers are reliant on independent contractors to provide energy efficient appliances and advise them of their benefits.</td></tr>
<tr><td>Goals</td><td>Short term goals:
Educate the market about the introduction of provincial regulations on September 1, 2010;
Educate consumers about choosing energy efficient water heaters and the importance of hot water conservation;
Upgrade a minimum of 3,600 hot water heaters to 0.62 EF or higher;
Promote contractor relations between the Companies and contractors, as well as between contractors and customers;
Engage manufacturers and distributors though co-marketing opportunities;
Engage retailers in the program; and
Engage the home insurance industry in early retirement messaging.
Long term goals:
Engage manufacturers in labeling tanks with an efficiency factor;
Promote the adoption of the next generation of ENERGY STAR® eligible models (0.67 EF or beyond);
Introduce a tankless and condensing water heater tier within the existing program; and
Lay the foundation for the national hot water market transformation strategy as outlined in Section 3.4.3.2.</td></tr>
</table>

Implementation	
Administration	Consumer Response Marketing Ltd.
Communications	FEI and FEVI engaged contractors, manufacturers, and big box retailers to co-promote the program. Contractor packs were mailed out to the BCSA database, and A.O. Smith, one of the largest water tank manufacturers, delivered program materials to their distribution network. Further promotions includeFortisBC.com, bill inserts, advertisements in community newspapers and trade publications, and retailer POP materials that were provided to both Rona and Sears. The following is a summary of the communications for this program: • FortisBC.com/efficientwaterheater; • Contractor packs mailed out to BCSA database; • Contractor packs included MEMPR's updated B.C Energy Efficiency Act Standards brochure to assist the province with compliance engagement; • John Woods distributed contractor packs to their dealer network; • Aug EEC "newsletter" bill insert with program highlighted; • Sept bill insert (one side); • Sept contractor program bulletin highlight; • Big box merchandising – Rona (launched Sept) & Sears (launched Oct); • Nov – Blackpress - ¼ page ads; • Dec EEC "newsletter" bill insert with program highlighted; and • Program collateral distributed at all CEO trade shows and street team events.
Evaluation Strategy	Program evaluation will include billing analysis in 2012 and potential surveys of distributors and contractors to monitor the trends in market penetration of high efficient and ENERGY STAR® eligible models.

3.4.2.1.2 2010 Program Results

Table 3-7: 2010 Efficient Hot Water Heater Storage Tank Results

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	152	15	52	243	1,990	20%	0.3
FEVI	20	2	12	32	269	20%	0.5
TOTAL	172	17	63	275	2,259	20%	0.3

The program's TRC is low when total program spending is compared to the avoided cost of natural gas. With the free rider rate estimated to be approximately 20 percent, the annual net energy savings derived from the program's participants is 275 GJs. However, the actual savings that should be attributed to this program are under-estimated by participation counts for the following reasons.

While developing the program, the Companies made contact with all major manufacturers in order to create an online directory of compliant tanks eligible for a rebate. Without the program, these stakeholders were less motivated to comply, since enforcement does not carry major penalties or ramifications. Because our customers were asking about a rebate, stakeholders such as manufacturers, dealers, contractors, and big box retailers were driven to comply. At least one manufacturer, who supplies a major big box retailer, re-designed their tanks in order to participate in our program. While 187 eligible models are listed on the NRCan directory, only a small portion of tanks can be purchased within BC. At the time of writing, only 10 different models have been approved for rebates. We continue to receive applications for non-compliant tanks, indicating they are still prevalent in the market.

Anecdotal feedback from the industry suggests that low participation rates are most likely due to the need for a gas permit, since there was a lot of initial excitement about the $50 dealer incentive. Our source estimates that only 20 percent of water tank installations are conducted with a permit. The EEC team is meeting with the BC Safety Authority ("BCSA") to determine if there are any ways that permit avoidance issues can be addressed.

3.4.2.1.3 2011 Program Performance Forecast

Table 3-8: 2011 Efficient Hot Water Heater Storage Tank Performance Forecast

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	2,980	429	138	5,722	47,415	20%	0.6
FEVI	745	107	34	1,430	12,043	20%	0.6
TOTAL	3,725	536	172	7,152	59,458	20%	0.6

The 2010 0.62 EF water heater program was introduced primarily as a compliance engagement program to be in the market until December 31, 2010; however, with lower than anticipated participation rates and anecdotal evidence of a large number of non-compliant tanks in market, the Companies are extending the existing base offer for the 2011 calendar year. This extension enables the Companies to promote hot water efficiency to manufacturers, contractors, retailers, and customers. The ongoing program also provides the opportunity to urge customers to not only replace their hot water tanks as an emergency purchase decision at the end of useful life, but to be proactive prior to tank failure. Partnerships with the home insurance industry are the best avenue to co-promote this message.

Most importantly, the base offer is the foundation for maintaining relationships with the supply chain required for the next stages of the DHW market transformation strategy. As we collaboratively work with stakeholders on a national strategy aimed at raising the bar on efficiency, it is important to have programs in place to guide the market and policy decisions. In addition to the $50 base offer for 0.62 EF tanks, the Companies are running a cost benefit analysis to introduce rebates for ENERGY STAR® models (0.67 EF and beyond), condensing water heaters, and tankless technologies. To date there are very few ENERGY STAR® water storage tank models that qualify and that are available in BC. In parallel to the 0.80 EF water heater pilot, the Companies will introduce rebates for condensing water tanks and tankless technologies. Although the TRC's on these new technologies are less than one, these programs are essential for market transformation.

Anecdotal evidence provided mixed reviews of tankless technology and therefore the Companies conducted an independent research study[18] to gather feedback on experience with early adopters of tankless technology. The results were very favourable and provide the Companies with confidence to proceed with promoting these products if energy savings estimates are validated.

The combination of financial incentives, contractor training, and effective marketing is key to the continued success of efficient water heater programs. The relationships developed to date in the 0.62 EF base offer are invaluable to furthering this work. In addition to energy efficient appliances, the opportunity to educate customers about the importance of water and hot water conservation adds additional societal benefits to this program.

3.4.2.1.4 Overall Summary

Although participation rates were lower than forecasted, the program was very successful in achieving its goals of compliance engagement, developing relationships with manufacturers, and gaining exposure for energy efficient water tanks in retail settings. The program confirmed that there is a great need for energy efficiency education across the hot water equipment supply chain – from manufacturers and distributors through to consumer education. This education will also help to ensure that customers who are replacing their tanks in an emergency situation will choose to install energy efficient tanks and will have access to energy efficient tanks through their installers.

This program is an important component in the overall strategy to help manufacturers, distributors, installers, and customers adopt the new provincial regulations that went into effect on September 1, 2010, which require all hot water tanks manufactured after that date to be 0.62 EF. The Companies will be actively evaluating tier three technologies (>0.8 EF) and developing a collaborative national hot water heater market transformation strategy as outlined in Section 3.4.3.2.

[18] Tankless Water Heater Study, National Survey to Homeowners, by TNS, commissioned by the Companies in October, 2010. Final report delivered December 14, 2010.

3.4.2.2 EnerChoice Fireplace Program

3.4.2.2.1 EnerChoice Fireplace Program Overview

ENERCHOICE FIREPLACE PROGRAM	
Target Audience	Residential Retrofit Customers
Duration	July 1, 2010 - Dec 31, 2011
Incentive	$150 for any EnerChoice fireplace with additional tiers to be introduced in 2011
Partner	Hearth Patio and Barbecue Association of Canada ("HPBAC")
Background	
Background	The EnerChoice fireplace program is an important program offering since natural gas fireplaces account for 13% of residential natural gas consumption based on 2010 CPR findings. In addition, 85% of customers have at least one fireplace or heating stove according to the 2008 Residential End Use Study ("REUS"). Consumer preferences for fireplaces can be categorized as those shopping for ambience versus those shopping for zone heat. Those focused on ambience often select decorative design features such as the flame, the rock or log set, and mantel design. Those focused on zone heat are more engaged in energy saving features such as electronic ignition switches or programmable remote controls, which allow users to turn off the fireplace and pilot light when the home is unoccupied. Through the evolution of EnerChoice fireplace programs, manufacturers are supplying more models that combine the attributes of ambience and energy efficiency. The Enerchoice program educates consumers to include energy efficiency as part of their fireplace purchase decision. The Enerchoice Fireplace label is a Canadian label reserved for products that meet or exceed efficiency levels as determined by an independent committee managed by HPBAC. Since there is currently no ENERGY STAR® rating for natural gas fireplaces, and there are no pending standards from the U.S. Department of Energy, the Canadian fireplace industry has developed its own efficiency label branded EnerChoice. The EnerChoice designation can only be applied to **free-standing stoves** with Fireplace Efficiency ("FE") 66% or higher, **fireplaces** that are 62.4% or higher, and **inserts** that are 61% and higher.
Description	In order to further educate consumers about the merits of energy efficient fireplaces, the 2010 EnerChoice program provides a $150 consumer rebate for EnerChoice purchases. The Companies are encouraging their customers to adopt energy efficient gas fireplaces designed for heating rather than simply decorative fireplaces for ambience.
Goals	• Encourage the sale and installation of energy efficient heater style fireplaces to reap the associated energy savings. • Further the education and awareness of the EnerChoice label to consumers and industry. • Further relationships with manufacturers and distributors of natural gas fireplaces through the HPBAC.
Implementation	
Administration	Consumer Response Marketing Ltd.

Communications	FEI and FEVI engaged HPBAC members to co-promote the offer through retailer and manufacturer channels. Promotions included online information, bill inserts, advertisements in community newspapers and trade publications, and events. Co-op advertising was introduced in Q4 2010 as requested by the industry.
Evaluation Strategy	EnerChoice Fireplace consumption data analysis on the 2008 and 2009 programs will be conducted in 2011 to validate energy savings claims for EnerChoice appliances. EnerChoice awareness surveys to consumers and dealers are being proposed to determine the market penetration of EnerChoice awareness and gain feedback for future program requirements.

3.4.2.2.2 2010 Program Results

Table 3-9: 2010 EnerChoice Fireplace Program Results

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	109	16	40	646	5,746	24%	1.0
FEVI	26	4	11	154	1,415	24%	1.1
TOTAL	135	20	51	800	7,161	24%	1.0

As outlined in Table 3-9, the program's TRC is positive. With free rider rate estimated to be 24 percent, the net energy savings over the lifetime of these measures is 7,161 GJs. Since program start-up costs are relatively expensive for marketing and administration, the TRC is expected to increase in 2011.

Program participation was lower than expected for a number of reasons. Firstly, it takes time to build awareness of a program for both customers and dealers. The program was launched to dealers in August and participation numbers are increasing over time. Secondly, 2010 sales were down as much as 25 percent over 2009 based on anecdotal feedback from the industry. Government incentive programs drove 2009 sales and 2010 sales were down by comparison. The 2010 program forecast was based on 2009 participation levels for dealer incentives. Many HPBAC members found the paperwork onerous and we felt that a consumer driven incentive would be more successful; however, there may be a need for further customer and dealer education about the benefits of EnerChoice. The Companies are developing a dealer and consumer survey to gain feedback on ways to make the program more effective for the 2011 iteration expected to be in market in the second quarter.

3.4.2.2.3 2011 Program Performance Forecast

Table 3-10: 2011 EnerChoice Fireplace Program Performance Forecast

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	1,920	576	117	11,309	102,031	24%	2.2
FEVI	480	144	29	2,827	25,963	24%	2.3
TOTAL	2,400	720	146	14,136	127,994	24%	2.2

In consultation with industry, the Companies are considering increasing the rebate from $150 to $300 in order to draw more attention to the benefits of EnerChoice and encourage customers to select even more efficient models. Since pilot lights consume substantial energy, another energy saving feature is an electronic ignition switch or a handheld fireplace remote-control that can be programmed to turn off the fireplace and the pilot light when the home is unoccupied. Therefore, a $50 incentive for these features is under consideration. Since a number of customers requested rebates for fireplace service as part of the "Give Your Furnace Some TLC" furnace service campaign, fireplace servicing may be included in the 2011 TLC campaign.

Given that higher program numbers were achieved with a dealer incentive, this may be re-introduced in the next iteration. HPBAC currently provides a $25 incentive for the first quarter of 2011. Response to this incentive will determine if the Companies will re-introduce a dealer incentive in the next iteration of the program. A number of dealers took advantage of co-op advertising, so this will also be considered in the 2011 re-launch.

Other partnerships may help promote the EnerChoice program. The Companies have been asked to partner with municipalities in the provincial Woodstove Exchange program. The EnerChoice offer is also listed in the LiveSmart BC program brochure to help raise awareness for customers who are doing whole home retrofits.

The combination of financial incentives, contractor training, and effective marketing is key to the continued success of the EnerChoice fireplace program. The relationship with HPBAC is fundamental to the continued success in order to actively engage dealers in promoting efficiency. By introducing program improvements, the program will provide significant energy savings and will remain an integral part of EEC programs in the future.

3.4.2.2.4 Overall EnerChoice Program Summary

With fireplaces accounting for 13 percent of residential natural gas consumption, it is critical to educate homeowners about the importance of choosing energy efficient models that are designed for zone heating rather than ambience. As more models become available the minimum efficiency standard can be increased over time. The Companies will continue to foster their relationship with HPBAC to drive program awareness and to assist in driving fireplace efficiency in the industry.

3.4.3 PROGRAMS IN DEVELOPMENT

3.4.3.1 Home Efficiency Measures Program

3.4.3.1.1 Home Efficiency Measures Program Overview

HOME EFFICIENCY MEASURES	
Target Audience	Residential Retrofit Customers
Duration	Proposed launch date of Q2 2011 and ongoing
Incentive	Coupon books and giveaways by promotional teams
Partners	Retail partners, distributors of energy savings equipment, utility partners, municipalities, and non-profits
Overview	
Background	There is an extensive list of low cost energy savings measures that, in combination with behaviour change initiatives, will result in substantial energy savings in the residential sector. Often these are homeowner “do-it-yourself” installations and many of these measures are contained in the Energy Saving Kits provided for low income households. Opportunities include the following: • Measures to reduce domestic hot water energy costs include ultra-low flow shower heads (please refer to Section 7.4.2.3 for information about the Water Saver pilot program), faucet aerators, hot water tank insulation, and pipe insulation; and • Measures to reduce home heating energy costs include programmable thermostats, weather-stripping, insulation, caulking, electrical outlet gaskets, and more.
Description	Build on opportunities for homeowners to self-install low-cost hot water and heat saving energy measures through community engagement programs, partner programs, retailer coupons, and distribution of the units at events.
Goals	• Develop a list of measures and their associated savings for inclusion in marketing materials, outreach activities, and conservation partnerships. • Capture energy savings associated with the installation of these measures • Develop partnerships to extend awareness and drive participant counts for these measures.
Implementation	
Administration	To be determined based on measure and activity.
Communications	Integrated marketing plan utilizing the Companies’ internal marketing opportunities and partnerships with retailers, distributors, government, and other utilities.
Evaluation Strategy	Evaluation will include the best approach to measure program effectiveness and capture energy savings estimates.

3.4.3.2 (0.80 EF) Hot Water Heater - PILOT PROGRAM

(0.80 EF) Hot Water Heater – PILOT PROGRAM	
Market	Retrofit and New Construction
Audience	FEI/FEVI Residential Homes
Duration	To be determined
Incentive	To be determined
Partner	Canadian Gas Association ("CGA")
Background	
Program Description	The purpose of the program is to obtain installation, performance, and customer acceptance information regarding residential Domestic Hot Water ("DHW") technologies with an Efficiency Factor ("EF") of 0.80 or better. The increasing importance of the water heating load has led the Ministry of Energy and Mines, in conjunction with Natural Resources Canada ("NRCan") to establish a plan to significantly raise minimum efficiency levels over the next 10 years. The Companies support these regulations since water heating is an important end use as it provides a "base load" throughout the year and helps keep the annual cost of natural gas purchases lower than it would be without the load. Water heating provides a relatively constant load over the year and hence provides revenue while not contributing incrementally to peak load. Peak gas is more expensive to acquire and as such, water heating load reduces the annual cost of natural gas to customers.
Technology Description	The main (0.80 EF) systems identified to date are: • On-demand or tankless water heaters; • Condensing tank water heaters; • Hybrid systems (on-demand heater mounted on or beside a small buffer tank); and • Combination systems (DHW and air/heat exchanger in one unit; may also include additional HRV or other functions).
Goals	• Replace existing low efficiency hot water tanks with (0.80 EF) hot water tanks to capture energy savings associated with reducing the overall consumption of natural gas. • Coordinate measurement solutions with stakeholders and/or third party companies to monitor systems performance and achieved energy savings. This data will be used to confirm savings claims and guide the development of future programs. • Engage the trades community and manufacturers by supporting (0.80 EF) hot water tank technologies. • Educate residential customers about the advantages of (0.80 EF) hot water tank technologies and provide incentives for their adoption when necessary. • Identify market barriers for adoption such as poor system performance, low product availability, lack of skilled contractors, low participant uptake numbers, and lack of awareness.

Status	A (0.80 EF) hot water heater pilot taskforce has been established with the CGA and Local Distribution Companies ("LDC") to discuss pilot rollout options and contributions on a national scale. An initial study, funded by the Companies, focused on the market transformation plan for DWHs prepared by Habart & Associates Consulting Inc. This study has been used as supporting documentation for the pilot program and includes a market transformation plan as well as performance estimates and installation costs for each selected (0.80 EF) hot water technology. This study revealed that there is a large technology gap between level two (0.67 EF) and level three (0.80 EF) equipment technologies. Level three technologies are just now emerging into residential applications and lack performance data, contractor familiarity, best installation practices, and product availability. The Companies conveyed those barriers to the stakeholders and all agreed that it would limit the success of reaching NRCan's 2016 regulation of (0.80 EF) hot water tanks. In late September, the CGA convened with NRCan and was successful in delaying those regulations from 2016 to 2020. Currently the Companies and stakeholders are establishing program design and monitoring solutions and incentive amounts for delivering the pilot program.
Implementation	
Administration	To be determined
Communications	To be determined
Evaluation Strategy	A proposal for handling administration, measurement, and evaluation for the (0.80 EF) hot water pilot program has been received from Natural Gas Technology Center ("NGTC") and is currently under review.

3.4.3.3 Furnace Scrap-it Program (Rebates and Financing Option Under Development)

3.4.3.3.1 <u>2012 Furnace Scrap-It Program Overview</u>

2012 FURNACE SCRAP-IT PROGRAM	
Target Audience	Residential Retrofit Customers
Duration	Proposed launch date of Q2 2012 and ongoing
Incentive	Combination of rebate and financing option being proposed
Partners	Ministry of Energy and Mines, financial institutions, and furnace manufacturers
Overview	
Background	Although the latest iteration of the ENERGY STAR® Heating System Upgrade Program was highly successful, there is much evidence that transformation of this market is not complete. The 2008 REUS suggests that only 16% of the Companies' residential customers have high efficiency furnaces (90% AFUE and higher), 39% have mid-efficiency furnaces (78% to 85% AFUE), and 45% have standard efficiency furnaces (less than 78% AFUE). This indicates that 84% of the Companies' customers have either a need to upgrade their standard efficiency furnaces or have mid-efficiency furnaces that are close to the end of their useful lives. There is a substantial need for incentives or financing options that would help remove financial barriers for proactive

	furnace replacement and a huge opportunity for energy savings and GHG emissions reductions through such initiatives. Furnace replacement was identified as a huge energy savings opportunity in the development of the Technical Potential of the 2010 CPR. There is enormous opportunity to significantly impact the age distribution profile of existing furnace stock. The Ministry of Energy and City of Vancouver are evaluating opportunities for financing programs for home efficiency upgrades. The EEC team will also investigate different financing models for home renovation loans that promote efficiency upgrades. There are challenges that need to be overcome in launching a Furnace Scrap-It program: • In traditional DSM environments, rebate programs cannot be in market for measures that are regulated. It would be essential that government stakeholders and regulators support this initiative in order to take it to market; • If the Companies were to actively promote early retirement it is important to include product stewardship as one of the program requirements to ensure that old furnaces are recycled safely; • Contractors, distributors, and manufacturers would be key to the successful rollout of this program. Adequate inventory would have to be in place and an assurance that no fraudulent mid-efficiency replacements took advantage of the offer; and • With the low cost of gas, it is difficult to convince customers that a new furnace has a direct pay-back with the full capital cost of the investment top of mind for the consumer. It would be beneficial to educate consumers about the additional benefits such as comfort, improved air quality, and furnace reliability. The national market penetration of high efficiency furnaces in Canada is reported to be 40%, while the Wisconsin Energy Conservation Corporation reports the market share of high efficiency furnaces in Illinois, Michigan and Ohio range from 52% to 73%. Wisconsin has achieved a 92% penetration. Market intelligence is difficult to obtain but an exact estimate for the province of BC would be beneficial. The enforcement of federal efficiency regulations apply only to the manufacturing of high efficiency models, but mid-efficiency models can still be sold. Therefore it appears that a sizeable inventory of mid-efficiency furnaces remain in the market. From time to time we see advertisements promoting the merits of mid-efficiency over high efficiency furnace replacement. The Companies are also gathering anecdotal evidence of lower efficiency furnaces that are due for replacement remaining in place and having repairs “jerry rigged” as a way to avoid some of the venting issues that British Columbians may face with the introduction of the government’s 90% efficient furnace regulation. The “Give Your Furnace Some TLC” furnace service campaign is one way of engaging customers in dialogues with contractors to promote replacement. In fact, program evaluation suggested that about 15% of participants required upgrades or replacements and participants cited financial considerations as the major barrier. Although we use 18 years as the measure of life for furnace upgrade, our 2010 programs indicate that customers are keeping their furnaces for a much longer timeframe. Participants in the Switch N Shrink oil conversion program report that replaced furnaces are 36 years old on average. while the furnace upgrade program participants report that replaced furnaces are 27 years old on average.
Goals	• Actively promote proactive furnace replacement with high efficiency furnaces to reap the associated energy savings of ENERGY STAR® heating systems, thereby substantially reducing GHG emissions in the residential sector. • Reinforce the compliance and market penetration of high efficiency furnaces with installers, distributors, and manufacturers.

	• In driving the market, further relationships with manufacturers, distributors, and installers of natural gas heating systems.
Description	This Furnace Scrap-it program, if implemented, will help remove financial barriers preventing homeowners from upgrading to ENERGY STAR® furnaces. This program is in the early stages of development and still requires discussions with a large number of stakeholders. The Companies are evaluating available market and technical data to establish a sound business case and cost benefit analysis before proceeding. If research suggests the program is viable, the Companies will consider launching a Furnace Scrap-It program in Q2 2012.
Implementation	
Administration	To be determined based on program direction.
Communications	Integrated marketing plan with financial partners and other stakeholders will be proposed during business case development.
Evaluation Strategy	TBD

3.4.3.4 EnerGuide 80 New Construction Program

ENERGUIDE 80 NEW CONSTRUCTION PROGRAM	
Target Audience	Builders and developers
Duration	Proposed launch date of Q2 2011 and ongoing
Incentive	Under development
Partners	BC Hydro, Ministry of Energy and Mines, Ministry of Housing, and CHBA Built Green
Overview	
Background	The Province of British Columbia is in the process of evaluating and developing new building code standards that would move the current EnerGuide 77 efficiency rating to a new target of EnerGuide 80 for new home construction. There is potential for the Companies to provide incentives to encourage the early adoption of EnerGuide 80 ratings for new home construction. FortisBC is working with internal and external stakeholders to understand the implications of the transition from the current BC Building Code to new EnerGuide 80 (EGH80) regulations scheduled for the fall of 2012. As new building codes will not take effect until 2012, now is the time to encourage builders and developers, through incentives, to begin building homes to the EnerGuide 80 standards. Ideally, incentives will help builders and developers define the prescriptive measures that will achieve EnerGuide 80 standards and prepare the market for the new building code changes. Through program implementation, FortisBC will gain a greater understanding about recommended measures, their costs and benefits, and how to build the larger strategic vision of lifecycle costs of natural gas heated homes versus electric. Through financial support, training programs for builders, and outreach to residential customers about the merits of efficient homes, FortisBC will support builders and developers in the transition to EGH80. Beyond EEC's New Construction Program, participation in the introduction of new building codes and standards are key to positioning natural gas attachments and the introduction of alternative energy systems. With the provincial mandate of Net Zero Ready homes by 2020, FortisBC must be positioned to play a role in these fundamental shifts in energy usage for

	the residential sector. For further discussion of building codes and standards please refer to Section 11.2.3.
Description	Extensive energy modelling and economic modelling has been conducted with the result that based on information available at the time of writing, the program does not pass the TRC. The Companies are working with the provincial government to determine the next steps for program implementation. The Companies intend to be involved in educating builders and guiding policy. A new construction program is essential to the Utility's role in the province's Energy Efficient Building Strategy[19].
Goals	• Develop a Residential New Construction Program to promote energy efficiency in new home construction and prepare the market for the introduction of the EnerGuide 80 building code for early 2012. • Through training and financial support, assist builders and developers in the move to more efficient construction practices to achieve EnerGuide 80 (i.e. building envelope measures, heating and hot water systems, and ENERGY STAR® appliance packages). • Understand the implications of EnerGuide 80 building code standards and beyond as they relate to gas heated homes. • Understand our role in developing or supporting the Ministry's prescriptive path for gas heated homes and recommend a strategy. • Strengthen relationships with developers, CHBA, BC Hydro New Homes program, and the trades community in relation to new construction. • Position our role as a gas supplier in ongoing codes and standards and Net Zero Ready homes. • Be vigilant about how changes to the EnerGuide rating system will affect future program planning. • Through program research develop a life cycle cost analysis for natural gas versus electric homes.
Implementation	
Administration	The Companies – internal accounting.
Communications	Develop an integrated marketing plan utilizing the Companies' internal marketing opportunities and partnerships with CHBA, other utilities, and trade publications. Target builders and educate consumers about the merits of EnerGuide 80 homes.
Evaluation Strategy	Evaluation will include the best approach to measure program effectiveness and capture energy savings estimates.

3.5 Summary

Overall the 2010 Residential Energy Efficiency Program Area was successful. The various programs and initiatives engaged customers in upgrading appliances to capture energy savings, supported the introduction of new provincial regulations, and reached out to the trades community for education and program awareness. The combination of financial incentives,

[19] BC Energy Efficient Buildings Strategy: More Action, Less Energy. BC Ministry of Energy and Mines Publication, 2008.

policy support, contractor outreach, and effective marketing is key to the ongoing success of these programs in generating natural gas savings and the culture of conservation in BC.

Programs in 2011 will focus on energy savings associated with re-launching improved iterations of the "Give Your Furnace Some TLC" furnace service program, efficient hot water heater storage tank program, and EnerChoice fireplaces. The Companies are also assessing opportunities for the new construction market and introducing initiatives for low-cost energy measures for homeowners. Feasibility studies and program implementation plans will be put in place for the launch of a Furnace Scrap-It program in 2012. In addition to energy and GHG emissions savings, the programs will assist the provincial government in engaging industry in regulation compliance and promote energy conservation messaging in all promotional materials. By engaging customers, trades, suppliers, and manufacturers in dialogues about energy efficiency, these programs propagate the conservation culture. The integration of EEC program goals is critical to the Companies' role in driving market transformation of energy efficient technologies for the residential sector.

4 COMMERCIAL ENERGY EFFICIENCY PROGRAM AREA

4.1 Overview

Commercial Energy Efficiency programs are aimed at encouraging commercial customers to reduce their overall consumption of natural gas and their energy costs. These programs are offered to both new construction and retrofit applications in FEI and FEVI service areas.

While residential programs focus entirely on single family dwellings, rowhouses, and townhomes (Rate Schedule 1 customers), commercial programs focus on a broader range of customer groups. The Companies serve over 80,000 commercial accounts, representing a wide variety of organizations, both private and public in nature. Commercial customers consume anywhere from 100 to over 40,000 GJ/yr, and are provided services through various customer rate schedules. Typical examples include small and large multi residential buildings, small businesses, food services such as restaurants, retail stores, large commercial office space, schools and universities, government buildings, hospitals, and manufacturing facilities.

Energy efficiency in the commercial sector represents a considerable opportunity to achieve natural gas savings and GHG emissions reductions. According to the Companies' latest Conservation Potential Review, in 2010 commercial customers consumed nearly 57 million GJs of natural gas and represent achievable potential natural gas savings of approximately 4.5 million GJ/yr by 2030. Notably, regulation of natural gas burning equipment is less prevalent for the commercial sector compared to the residential sector, even though higher efficiency options exist. This means there are a great number of cost effective opportunities available to the Companies to encourage reduced natural gas consumption in the commercial sector via demand side management ("DSM") programs; however, reaching out effectively to commercial customers presents challenges. Most importantly, the great diversity of natural gas burning equipment and systems and associated solutions imposes significant resource requirements on program development, delivery, and administration. Ultimately, capturing the considerable natural gas savings offered by the commercial sector requires the dedication of correspondingly significant resources in order to effectively target the diverse needs of the commercial sector.

Overall, the Companies believe the commercial energy efficiency and conservation programs deliver value by effectively encouraging commercial customers to implement measures that reduce their natural gas consumption, helping keep energy costs low and contributing to the realization of the government's energy and climate objectives.

4.1.1 PROGRAM AREA GOALS

The Commercial Energy Efficiency programs pursue a number of objectives in order to deliver value. More specifically, they focus on:

- Reducing natural gas consumption and GHG emissions by encouraging commercial customers to upgrade from low efficiency to high efficiency systems and/or change their behaviour;
- Precipitating market transformation by educating commercial customers, tradespeople, and design professionals about the advantages of energy efficient options, as well as building capacity among suppliers/manufacturers and the trades community; and
- Prudently investing in supporting customer capital asset upgrades.

In support of the objectives outlined above, the Companies also strive to:

- Develop cost effective programs with a Total Resources Cost ("TRC") score greater than 1.0 that optimize the proportion of incentives over administration and marketing costs; and
- Conduct program evaluations that confirm savings claims and guide the development of program enhancements and future programs.

4.2 2010 Commercial Program Area Results

Table 4-1 provides a summary of the commercial program area's performance in 2010. The commercial program area has delivered natural gas reductions while maintaining a very healthy overall cost benefit (TRC) score of 1.7 for FEI and 1.8 for FEVI; however, overall investment remains below budget levels, indicating additional work and resources are required to ramp up to the approved spending limits and maximize natural gas savings.

Table 4-1: Value from Commercial Energy Efficiency Programs in 2010

Program	New Const / Retrofit	Incentives & Non-Incentive			NPV Energy Savings (GJ)			TRC	
		FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Efficient Boiler Program	New Const	75	6	81	27	1	28	1.6	1.3
	Retrofit	1,213	103	1,315	379	30	408	1.4	1.2
Light Commercial ENERGY STAR® Boiler Program	New Const	1	-	1	1	-	1	4.8	0.0
	Retrofit	95	13	108	65	7	72	1.6	1.2
Efficient Commercial Water Heater Program	New Const	-	-	-	-	-	-	0.0	0.0
	Retrofit	19	4	22	5	1	6	1.1	0.9
Energy Assessment Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	91	17	108	17	4	22	2.4	2.9
PSECA Initiative	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	554	302	856	163	108	271	2.4	2.2
Spray N' Save 2010	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	16	16	N/A	6	6	N/A	3.9
Fireplace Timers Pilot Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	10	-	10	2	-	2	2.3	0.0
	TOTALS	2,056	461	2,517	659	157	817	1.7	1.8

The Commercial Energy Efficiency programs have encouraged commercial customers to reduce their annual natural gas consumption by approximately 104,000 GJ/yr, equivalent to over 817,000 GJs over the lifetime of the energy saving measures. This is equivalent to providing natural gas to nearly 1,100 single family homes or taking over 1,050 cars off the road[20] over the same period. As a result, approximately 5,260 tons of annual GHG emissions will be avoided.

Within the current climate of low natural gas prices, this represents a remarkable success as the price of natural gas cannot be considered a driver of energy efficiency upgrades to any great extent, except in those customers with very high gas consumption or where natural gas is an input into some business process. Although the current price of gas can make it a challenge to find cost effective energy saving measures to incent, it reinforces the need for energy efficiency programs in order to achieve the government's energy and climate change objectives. With low natural gas prices, some customers are not motivated to save without utility encouragement. Energy Efficiency and Conservation programs then become necessary to drive long term market transformation towards improved efficiency.

A few additional highlights from 2010 include:

- Over $2.4 million committed as incentives to energy efficiency projects;
- A 58% increase year over year in Efficient Boiler program participation;
- The launch of the Efficient Commercial Water Heater program;
- Participation in the Public Sector Energy Conservation Agreement in partnership with the Climate Action Secretariat and BC Hydro; and
- Work with BC Hydro to develop joint program offerings (Refer to 4.4.3.2 Commercial Custom Design Program).

While the commercial programs have done well on a number of counts, the Companies have also faced challenges and identified areas for improvement. With just over $2.5 million expended in this program area, the commercial programs have ultimately underinvested when compared to the approved amounts. This underinvestment represents opportunities to reduce natural gas consumption that have not been capitalized upon. This situation is a result of the considerable diversity of needs among commercial customers and a requirement for sufficient EEC resources to address those needs. When it comes to commercial area DSM programs, one size does not fit all. While the Companies' initial focus has been to develop and operate DSM programs around technologies with broad applicability to the commercial sector, investing more and obtaining greater savings requires a more focused approach, with programs tailored to meet the needs of specific subsectors. This approach will necessarily require resources to be able to focus more specifically on the needs of the various subsectors. Beyond program design, relationships with outside organizations and associations are crucial to program success and these must be cultivated. The Companies must have the resources in place to invest the required time and effort to build trust and confidence with partners in order to help assure program success.

[20] Based on five tons of carbon dioxide per year for a typical mid-sized car driven 20,000 kilometres per year. Source: Statistics Canada, accessible at: http://www.statcan.gc.ca/pub/16-251-x/2006000/findings-resultats/greenhouse-serre/4156371-eng.htm .

Additionally, with the absence of program operations personnel or an outsourcing solution, the commercial EEC team spends a considerable amount of time on program administration as opposed to program design and roll out, thereby slowing the introduction of new programs and hindering the ability to invest in commercial EEC program development activity. Receiving and processing applications, contacting customers for missing documentation, responding to enquiries, and issuing incentive payments are all handled by the program design staff, who should be otherwise focused on developing and promoting new programs. The Efficient Boiler program process, in particular, is complex and requires much support from EEC staff in order to see participants successfully through the program and to ensure rebates are ultimately issued. A revision to the program is currently under development and designed to simplify the process to free up many hours that can be redirected towards more valuable work. Administrative work is central to ensuring predictability, consistency, and continuity of the commercial area programs, however, and cannot be neglected. Commercial customers must view the programs as being reliable if they are to be encouraged make decisions that will have an impact in the medium term based on the availability of an incentive from the Companies.

Despite these challenges, the Companies consider this first full year of operation under the EEC project to have been a foundation year for the Commercial Energy Efficiency programs. Valuable experience has been developed while relationships with partners in utilities, government, and industry have been fostered. The Companies now intend to build upon this foundation to deliver even greater value in 2011.

4.3 2011 Commercial Program Area Outlook

The Companies intend to broaden their commitment to Commercial Energy Efficiency programs in 2011. Table 4-2 provides an overview of some of the expected program spending, and a glimpse of the new program offerings the Companies' have under development. In addition to retaining many of the existing commercial programs the Companies intend to bring several new programs to market. Most notably, the Commercial Custom Design Program will begin providing incentives in tandem with BC Hydro's incentive programs. The outlook for these programs is outlined below.

Table 4-2: Broader Offering for Commercial Energy Efficiency Programs in 2011

Program	New Const / Retrofit	Incentives & Non-Incentive			NPV Energy Savings (GJ)			TRC	
		FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Efficient Boiler Program	New Const	200	13	212	73	2	76	1.6	1.2
	Retrofit	1,334	113	1,447	425	35	460	1.4	1.4
Light Commercial ENERGY STAR® Boiler Program	New Const	15	-	15	10	-	10	1.6	0.0
	Retrofit	165	32	197	114	17	132	1.6	1.2
Efficient Commercial Water Heater Program	New Const	8	3	11	3	1	3	1.2	1.3
	Retrofit	108	9	118	40	3	43	1.2	1.0
Energy Assessment Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	100	19	119	19	5	24	2.7	3.3
PSECA Initiative	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	824	216	1,040	323	59	382	0.7	1.0
Low Flow Spray Valve Program	New Const		-			-		1.9	0.0
	Retrofit	23	5	28	8	2	9	2.4	2.4
Fireplace Timers	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	20	2	22	5		5	2.5	2.0
Radiant Tube Heaters Pilot Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	10	-	10	3	-	3	1.5	0.0
Commercial Custom Design Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Continuous Optimization Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Commercial Cooking Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Process Heat Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Multi Unit Residential Building Program	New Const	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Retrofit	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	TOTALS	2,805	412	3,217	1,023	124	1,146	1.2	1.2

Expenditures from new programs (indicated in grey shade) are not included in the table above as work on business cases or detailed program design is in progress, thus preliminary spending estimates are not yet available. As a result of the introduction of new programs in 2011, the Companies expect to spend significantly more than the approximately $3 million indicated above.

Collectively, this portfolio will continue to create value in 2011 with the important stakeholder group of commercial customers, while laying a foundation for continued EEC efforts in 2012 and beyond.

4.4 Commercial Program Details

Program descriptions for each of the Companies' commercial energy efficiency offerings follow below. Table 4-3 provides an overview of the commercial incentive programs, indicating which programs were completed in 2010, which programs remain active moving into 2011, and which programs are currently under development.

The commercial programs generally maintain very strong TRC test scores. With more limited regulation, higher natural gas use intensities, and most importantly a greater diversity of gas burning systems and equipment than for residential customers, finding cost effective opportunities for investment is generally easier for the commercial program area. Capitalizing upon those opportunities, however, requires greater time, effort, and resources.

Table 4-3: Commercial Program Overview

Program	Utility		Description	TRC	
	FEI	FEVI		FEI	FEVI
Completed Programs					
Spray N' Save 2010 Program	N/A	X	Free provision and install of low flow pre rinse spray valves. Partnership with BC Hydro.	N/A	3.9
Active Programs					
Efficient Boiler Program	X	X	Rebate program for high efficiency commerical boilers > 300 MBH Input.	1.4	1.2
Light Commercial ENERGY STAR® Boiler Program	X	X	Rebate program for high efficiency commerical boilers < 300 MBH Input.	1.6	1.2
Efficient Commercial Water Heater Program	X	X	Rebate program for high efficiency commercial water heaters with thermal efficiency > 84%.	1.1	0.9
Energy Assessment Program	X	X	No charge energy use assessments of commercial facilities.	2.4	2.9
PSECA Initiative	X	X	Financial incentives for cost effective energy saving measures presented in an Energy Study. Partnership with Ministry of Environment.	2.4	2.2
Fireplace Timers Pilot Program	X	X	Pilot program to assess the natural gas savings potential of fireplace "time-of-operation" controllers in multi-unit residential buildings.	2.5	2.0
Radiant Tube Heaters Pilot Program	X	X	Pilot program to assess the incremental costs and savings potential of radiant tube heaters when used for space heating in place of standard unit heaters.	1.5	0.0
Programs in Development					
Low Flow Spray Valve Program	X	X	Free provision and install of low flow pre rinse spray valves. Partnership with Green Table.	2.3	2.4
Commercial Custom Design Program	X	X	Financial incentives for cost effective energy saving measures presented in an Energy Study. Partnership with BC Hydro.	N/A	N/A
Continuous Optimization Program	X	X	Incentive program to capture energy savings via building commissioning. Partnerships with FortisBC and BC Hydro.	N/A	N/A
Process Heat Program	X	X	Rebate program targeted at Manufacturing processes.	N/A	N/A
Commercial Cooking Program	X	X	Rebate program targeted at commercial cooking appliances.	N/A	N/A
Multi Unit Residential Building Program	X	X	Suite of Rebates targeted primarily at "In-Suite" energy saving measures for MURBs.	N/A	N/A

4.4.1 COMPLETED PROGRAMS

4.4.1.1 Spray N' Save 2010 Program

4.4.1.1.1 Program Overview

Spray N' Save 2010 Program	
Market	New Construction / Retrofit
Duration	FEI: Not available FEVI: May 2010 to Aug 2010
Incentive	Direct install of low flow pre rinse spray valves funded entirely by the Companies
Partner	BC Hydro

Overview	
Background	Low flow pre rinse spray valves use approximately 50% less water than standard models[21], significantly reducing the volume of heated water used in dishwashing operations. This, in turn, reduces the energy demands placed on the hot water system, and thereby the overall energy consumption of a given facility. Pre-rinse Spray Valves ("PRSVs") are commonly used in restaurants, hotels, schools, grocery stores, and hospitals to rinse down plates, pots, and pans.
Description	A direct install program for low flow pre rinse spray valves offered in partnership with BC Hydro, focusing on an as yet underserved population centre: southern Vancouver Island. FEVI installed, free of charge, new low flow pre rinse spray valves in willing food service facilities (i.e. restaurants, coffee shops, delis, groceries, and so on) in order to reduce the volume of hot water used in dishwashing. The program focused on southern Vancouver Island, specifically: the Capital Regional District, Cowichan Valley Regional District, and the Nanaimo Regional District. Similar to the Okanagan program offered in the summer of 2009, it achieved a reduction in natural gas consumption associated with the production of hot water by reducing hot water use in commercial kitchens.
Goals	• Reduce natural gas consumption associated with dishwashing by installing low flow pre rinse spray valves in food service establishments. • To install 250 to 300 spray valves in southern Vancouver Island over the course of the summer. • To achieve gas savings of approximately 2,200 GJ/year and save our FEVI customers approximately $28,000 in annual gas expenditures. • To raise awareness of energy efficiency, especially as it pertains to water heating, among FEVI's commercial cooking customers, with a view to increasing participation in FortisBC commercial programs. • To pursue a commercial cooking equipment program and use the information from this pilot to gather lists of potential participants.
Implementation	
Administration	The program was implemented by a program operator working out of the FEVI offices in Victoria, reporting to the EEC commercial program manager in Surrey. The program operator was responsible for seeking out and making contact with potential program participants, answering questions about the program and the valves, scheduling appointments, installing the valves at all participant locations, recording field data, and producing a final report on the findings.
Communications	The program's requirement for communications material or collateral was relatively light. Program promotions and participant uptake was driven primarily by the program operator. As such, communications / collateral requirements were limited to: 1. Participant consent form; 2. Information card to hand out to participants or potential participants; and 3. A website to inform potential participants about the program and allow them to request the installation of a low flow spray valve.

[21] FortisBC 2010 Spray 'n' Save Victoria Program Results.

Evaluation Strategy	The program evaluation relies upon site specific data collected during the valve install and the application of engineering analysis to establish the energy savings. For each valve installed the program operator measured: • The hot water supply temperature; • The cold water supply temperature; • The old valve flow rate; and • The new valve flow rate. The operator also recorded the time of usage as reported by the restaurant staff. These data were then used to establish the natural gas savings for each valve. All savings data was then statistically analyzed to produce an average savings value per valve. The program made use of collected data pertaining to every installation and analytical methods to quantify the energy savings. The results of the program were presented in a report format and were used as a baseline for the 2011 Low Flow Spray Valve Program (section 4.4.3.1).

4.4.1.1.2 2010 Spray N' Save Program Results

Low flow pre rinse spray valves continue to generate a strong cost benefit ratio and save significant amounts of natural gas among commercial food service establishments. The 2010 program focused on southern Vancouver Island and delivered a TRC score of 4.0, as indicated in Table 4-4 below.

Table 4-4: 2010 Spray N' Save Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	FEI	-	-	-	-	-	12%	0.0
	FEVI	194	12	4	1,529	6,322	12%	3.9
	TOTALS	194	12	4	1,529	6,322	12%	3.9

With a total of 263 low flow pre rinse spray valves installed, the 2010 Spray N' Save program successfully surpassed its target of 255 valves. Using data collected during the installation of the new valves, the total natural gas savings are estimated to be 2,073 GJ/yr; enough to provide natural gas to approximately 20 single family homes for a year. This figure may well be conservative as it assumes a 50/50 mix of hot and cold water (i.e. 98° F supply temp) at the spray valve. Mixed water temperatures are often more in the range of 105° F. Additionally, the measured water temperature differential between hot and cold water is based on summertime cold water temperatures. In winter, when the ground temperature falls, so too will the cold water supply temperature, thereby increasing the savings of the spray valves. Overall, the program invested over $20,000 in natural gas efficiency over the course of the summer.

The program displays a very positive cost/benefit ratio of 4.0. In fact, it is estimated that, given the maximum installed cost of approximately $130 per valve, the average full service commercial food service establishment would recoup the full cost of the valves in approximately one year from the date of installation. With a five year measure life, participants enjoy the financial net benefit of lower gas consumption every year thereafter. One may question why a utility supported DSM program is required, given the strong value proposition low flow pre rinse spray valves represent. The Companies believe that despite the value proposition, the dynamics of the food service industry make it unlikely this measure would be widely adopted without the support of a program. The commercial food service business sector tends to be exposed to significant volatility, making “cheapest first cost” a critical purchase decision criteria for items not critical to customer service. Food service establishments typically lack the time or resources to research energy saving options or understand the benefits provided. Though low flow spray valves pay for themselves relatively quickly, the ultimate magnitude of the dollar savings per any single valve is unlikely to move most potential beneficiaries to action. A utility funded DSM program makes it easy and straight forward for participants to save natural gas by effectively eliminating both the effort and risk potential participants would normally associate with the selection of high efficiency options.

The spray valve program also plays an important role in introducing a new concept to the food service industry, namely that energy is a variable cost. The Companies believe most food service establishments consider energy to be a fixed cost and that changing this mindset is essential to ultimately bringing about market transformation. In this light, the Companies believe low flow pre rinse spray valve programs are an essential first step that will lead to greater energy savings down the road.

4.4.1.1.3 2011 Spray N’ Save Program Performance Forecast

The Spray N’ Save 2010 program was set up as a small program, limited to the southern end of Vancouver Island. The Companies plan to offer another low flow pre rinse spray valve install program in 2011; however, a number of significant changes to the program operation are proposed. As such the 2011 program is discussed in section 4.4.3.1.

4.4.1.1.4 Spray N’ Save Program Summary

The program installed 263 low flow pre rinse spray valves in locations that had previously used standard flow rate sprayers, generating significant natural gas savings as a result. Commercial food service operators have become aware of the low flow option and in nearly every case have indicated they are satisfied with the performance. In fact, of the original 265 valves installed, only two were uninstalled due to dissatisfaction. The Companies believe the program has successfully generated tangible GJ savings benefits, as well as non-tangible benefits derived from raising energy awareness in the commercial food service sector.

4.4.2 ACTIVE PROGRAMS

4.4.2.1 Efficient Boiler Program

4.4.2.1.1 <u>Program Overview</u>

Efficient Boiler Program	
Market	New Construction / Retrofit
Duration	FEI: 2005 – Dec 31, 2011 FEVI: 2005 – Dec 31, 2011
Incentive	Purchase price incentives (rebates): • Near-condensing boilers: $4,000 per boiler plus $3 per MBH plant input; and • Condensing boilers: $6,000 per boiler plus $9 per MBH plant input. For new construction participants the program offers: 1. A maximum incentive payment (calculated as noted above) of up to 75% of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input; and 2. An incentive payment of 50% of a consultant's fees to a maximum $1,500 to offset the cost of analyzing the annual gas usage for space heating using a standard-efficiency boiler system versus a higher efficiency boiler system. For retrofit participants the program offers: A maximum incentive payment (calculated as noted above) of up to 50% of the incremental purchase price of higher efficiency boilers. The purchase price of a standard-efficiency boiler is estimated using $7 per MBH of input; 1. An incentive payment of $400 to help offset the cost of engaging a contractor to accurately estimate the peak space-heating load; 2. Where stainless steel venting is installed, an incentive of 50% of the cost up to $2,000; and 3. For participants who so choose, a monitoring incentive of $1,500 plus $1 per GJ of energy saved for closely monitoring and reporting on boiler operation and efficiency during the first year of operation.
Partner	None
Overview	
Background	Approximately 60% of commercial gas consumption in BC is used for space heating. High efficiency boiler technology, when used as part of a properly designed heating system, generates significant annual energy savings over a comparatively long estimated measure life. In fact, high efficiency boilers represent one of the most significant sources of achievable savings for the commercial sector in BC[22]. Fully 19% of such savings is attributable to high efficiency boilers. Minimum required boiler efficiencies are regulated within the province by the British Columbia Energy Efficiency Act and the Energy Efficiency Standards Regulation. Similarly, minimum boiler efficiencies are regulated in Canada as a whole by the

[22] FortisBC 2010 Conservation Potential Review, Commercial Sector Report, Marbek Resource Consultants, 2011, pg 55.

	federal Energy Efficiency Act. These acts regulate products manufactured in or imported to Canada and BC for domestic sale. Current regulation generally requires boilers to have a minimum efficiency of 80%. A proposed amendment to Canada's energy efficiency regulations would see the minimum required combustion efficiency of large boilers climb to 90% over the same period. The Efficient Boiler program is helping ease implementation of this proposed regulation by familiarizing market participants with high efficiency technology prior to the implementation of more stringent regulation.
Description	In operation since 2005, the Efficient Boiler program is FEI and FEVI's flagship Commercial Energy Efficiency program aimed at reducing gas consumption associated with space heating. By encouraging the use of high efficiency boilers, the Efficient Boiler program directly targets the commercial sector's most significant source of gas consumption (space heating) via one of its most widely used and longest lasting gas burning appliances (boilers). Installing such boilers today has a lasting impact by reducing gas consumption now, while paving the way for market transformation and ultimately more stringent regulation of commercial boilers.
Goals	• Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency boilers for space heating. • Increase year over year participation rates in view of maximizing gas savings. • Educate medium to large commercial customers about the advantages of high efficiency boilers and provide an incentive to facilitate the purchase of high efficiency technology. Support and prepare the way for any provincial or federal regulation requiring increased boiler efficiency. • Advance the level of skill, capacity, and understanding within trades/mechanical contractors on the correct installation practices and requirements of modern high efficiency commercial boilers. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
Implementation	
Administration	Program administration is handled entirely in-house by the Companies' EEC Staff. Shifting program administration to an outside service provider or dedicated program operations personnel is a requirement in 2011 in order to free up internal resources to be redirected towards new commercial program development and roll out.
Communications	• www.fortisbc.com – All program information, application forms, and program terms and conditions were maintained on the Efficient Boiler program webpage. • Commercial customer outreach initiative that saw the Companies call over 80,000 commercial customers to provide information on the Efficient Boiler program, among others. • Advertisements in American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE) newsletters and the Association of Professional Engineers and Geoscientists of British Columbia's ("APEGBC") magazine. • Stakeholder focus group/feedback session in June 2010 with suppliers, contractors, engineers, participants and potential customers, energy managers, and safety officials. • Speaking engagements / presentations describing the program at events such as: BC Apartment Owners and Managers Association semi-annual tradeshows, Rental Owners and Managers Society of BC tradeshow, NRCan "Spot the

	energy savings" workshop on Vancouver Island, BC Hydro PowerSmart forum, BC Hydro energy managers training session, FortisBC energy specialist training session, Vancouver Home Show, Union of BC Municipalities Whistler 2010, Business Improvement Association meetings in Victoria, Kamloops, and Kelowna, and Council of Education Facilities Planners International conference. • Tradeshow booth/presence at: BC Agriculture tradeshow, BC Food and Restaurant Association tradeshow, Buildex tradeshow, BC Apartment Owners and Managers Association semi-annual general tradeshows, and Rental Owners and Managers Society of BC tradeshow. • Program brochures describing the program specifics and how to apply were handed out at the presentations and tradeshows mentioned above. • Information distributed to all customer touch points including call centres, sales and service staff, and commercial account managers.
Evaluation Strategy	In 2010 the Companies: 1. Completed a focus group session with program stakeholders to find out how various stakeholder groups view the program and to seek input on a revised program structure aimed at better serving stakeholder interests; and 2. Began an evaluation study (performed by a third party consultant) of natural gas savings using actual metered data and statistical methods to better quantify the savings of the program. These two initiatives will serve as an evaluation of the Efficient Boiler program from both the quantitative and qualitative perspectives.

4.4.2.1.2 <u>2010 Efficient Boiler Program Results</u>

With a solid net benefit-to-cost ratio, high efficiency boilers continue to generate a respectable TRC ratio of 1.4. Given a 58 percent increase in participation versus 2009, the Efficient Boiler program has ramped up its presence in the market and delivered significant natural gas and GHG emissions savings in 2010, as indicated in Table 4-5 below

Table 4-5: Efficient Boiler Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	3	74	1	2,630	27,055	18%	1.6
	FEVI	1	6	1	103	1,097	18%	1.3
Retrofit	FEI	88	1,189	23	36,802	378,622	18%	1.4
	FEVI	8	97	5	2,919	29,642	18%	1.2
	TOTALS	100	1,367	30	42,453	436,416	18%	1.4

In 2010, a record number of customers applied to the Efficient Boiler program, choosing high efficiency boilers over standard models. The program significantly outperformed expectations in this regard. As of the writing of this report, the program had officially recorded 100 approved participants with another 15 pending a review of their submitted documentation. By comparison, 2009 saw only 67 applicants in total, 63 of which were accepted into the program as approved participants. The next closest year in terms of participation was 2006, which saw a total of 100 applications received. The Companies believe the increased participation is a result of sustained efforts at promoting both the program itself and the Energy Efficiency and Conservation project more generally, at all available opportunities. The Companies also believe stability and consistency in the program offering (i.e. staying in market over the long term) contributes significantly to encouraging adoption of the high efficiency alternative. The decision to purchase high efficiency boilers is much influenced when the market's awareness of the program is reinforced by its time in market, and when the accepted view of the program is as a reliable source of incentives for high efficiency options.

As indicated in the "Background" section of the Table above, new efficiency regulations are currently being considered by the Government of Canada (Natural Resources Canada). The proposed regulation would see the required minimum efficiency standard of larger gas fired boilers rise from 80 percent to 90 percent by 2018. Successful installation and commissioning of high efficiency boilers requires a knowledge level beyond that of standard efficiency boilers. The Companies believe the program sends a strong signal to the market that the selection of high efficiency options should be adopted as standard practice. By encouraging the installation of high efficiency boilers today, the program is contributing to the development of the required knowledge and capacity within the market, significantly easing the implementation of new regulation over the coming years.

By year end, the efficient boiler program had committed to pay as much as $1,367,000 (not including pending applications) to participants who successfully complete their boiler installation within one year of submitting their program application. This exceeds the previous largest ever annual commitment of $1,075,455 from 2006. As in 2009, the objective moving forward is to build upon the current market momentum and the relationships that have been built with market participants to drive the rate of participation in the program in order to maximize commercial sector gas savings.

When total program spending is compared to the avoided cost of the gas, the program turns in a respectable TRC ratio of 1.4. With the free rider rate estimated to be approximately 18 percent, the annual net energy savings derived from the program's 2010 participants is over 42,000 GJs, or over 2,000 tons of GHG emissions reductions. This represents a volume of gas equivalent to the annual consumption of approximately 450 typical single family homes.

That said, room for improvement in the program remains. While the program largely met its objectives for participation on Vancouver Island, participants from the new construction market remain sparse. According to the available Major Projects Inventory quarterly publications, the value of building permits remains well below the peak activity level observed in 2007 and 2008, indicating new construction activity remained generally subdued in 2010. Still, 55 projects of $15 million or more completed construction between January and September, while 65 began construction. Having garnered only nine new construction participants in 2010, it seems evident that raising the program's profile and generating participation in the new construction market remains a priority. This is despite the Companies' efforts at promoting the program to design professionals via advertisements in both ASHRAE BC and APEGBC's regular publications. More work at promoting the program to decision makers in the new construction marketplace is a must. The Companies' new energy solutions manager positions (see Section 11) will play a central role in this effort by communicating directly with design professionals around the province. The Companies also still believe there is room for participation growth on Vancouver Island and maintaining promotional activity on the Island is critical to developing momentum and uptake.

4.4.2.1.3 *2011 Efficient Boiler Program Performance Forecast*

No significant changes to the cost benefit relationship of high efficiency boilers are foreseen, thus the Companies anticipate the program will continue to generate a TRC ratio of approximately 1.4. The Companies further expect the Efficient Boiler program to build incrementally upon its 2010 participation as reflected in the table below.

Table 4-6: Efficient Boiler Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	8	197	2	7,013	73,434	18%	1.6
	FEVI	2	12	1	205	2,190	18%	1.2
Retrofit	FEI	97	1,308	25	40,482	424,785	18%	1.4
	FEVI	9	107	6	3,211	35,091	18%	1.4
	TOTALS	116	1,625	35	50,911	535,500	18%	1.4

Two key initiatives were undertaken in 2010 that will guide activity around the Efficient Boiler program in 2011. First, in June 2010 the Companies conducted a stakeholder focus group to help raise awareness of the program and provide needed and direct insight from industry participants on the program's structure and operation. Second, in September 2010 the Companies began an in-depth, quantitative evaluation study of the program's performance in reducing natural gas consumption. The initial results suggest the natural gas savings are very much in line with what the Companies are currently claiming (approximately 15 percent reduction). The findings of these two initiatives will be used to restructure the program's processes, verify the savings assumptions, and readjust the incentive levels if the cost benefit analysis allows.

As a result of this work and experience gained throughout 2010, the Companies are undertaking revisions to the Efficient Boiler program with program elements designed to focus on three distinct markets:

1. Simple retrofits and new construction;
2. Detailed complex retrofits and new construction; and
3. Operations and maintenance.

The first program element, targeting simple retrofits and new construction, is expected to be operational in 2011. Based on feedback from program participants, this component of the program seeks to

- Make the incentives clear and straightforward to simplify the purchase decision; and
- Reduce the program's administrative burden / overhead for the Companies.

The second and third program elements, focusing on more detailed system design and boiler plant operations and maintenance, will likely be operational in 2012.

In addition, the program will expand the end uses that are eligible for an incentive. Currently, the program only provides incentives for boilers used for space heating. Different end uses are precluded from incentives due to the difficulty in establishing reasonable natural gas savings estimates. Commercial pool and water heating, however, may reasonably be included for incentives moving forward. Commercial pool heating, in particular, is a significant and unaddressed consumer of natural gas and, especially in the case of municipalities, represents an area where program incentive money can make a tangible difference to energy consumption and GHG emissions

It is believed these proposed changes, combined with sustained promotion of the program, will allow the Companies to further the penetration of high efficiency boiler technology in both the retrofit and new construction markets by making the program more visible and accessible to potential participants. Increasing the program's participant numbers furthers the Companies' goal of reducing the commercial sector's gas consumption and bringing about market transformation.

At present, participation is forecasted to grow at a reasonable 10 percent for the key FEI retrofit market; however, the Companies believe additional growth can be expected in the new construction and Vancouver Island markets. Central to this will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the program's application process.

4.4.2.1.4 Efficient Boiler Program Summary

The Efficient Boiler program effectively encourages program participants to adopt high efficiency boilers in a market where standard efficiency alternatives remain prevalent. The program is helping pave the way for more stringent regulation by encouraging the market to develop the required competency and capacity to deal with high efficiency boilers now. Incremental increases in participation, in conjunction with the benefits derived from a program overhaul, will add significantly to the natural gas savings and dollar investment potential of the program by making it more accessible to a broader range of market participants.

4.4.2.2 Light Commercial ENERGY STAR® Boiler Program

4.4.2.2.1 Program Overview

Light Commercial ENERGY STAR® Boiler Program	
Market	New Construction / Retrofit
Duration	FEI: Aug 2009 – Dec 31, 2011 FEVI: Aug 2009 – Dec 31, 2011
Incentive	Providing that the boiler is used for space heating and/or domestic water heating in combination with space heating: • Condensing boilers: $5 per MBH; and • Near condensing boilers: $3 per MBH. Incentives are available for ENERGY STAR® rated boilers ranging in size up to 299 MBH. Beyond 299 MBH no ENERGY STAR® rating is available, and boilers are covered by the Efficient Boiler program.
Partner	None
Overview	
Background	Approximately 60% of commercial gas consumption in BC is used for space heating. High efficiency boiler technology, when used as part of a properly designed heating system, generates significant annual energy savings over a comparatively long estimated measure life. In fact, high efficiency boilers represent one of the most significant sources of achievable savings for the commercial sector in British BC[23]. Fully 19% of such savings is attributable to high efficiency boilers. Minimum required boiler efficiencies for small boilers are regulated within the province by the British Columbia Energy Efficiency Act and the Energy Efficiency Standards Regulation. Similarly, minimum boiler efficiencies are regulated in Canada as a whole by the federal Energy Efficiency Act. These acts regulate products manufactured in or imported to Canada and BC for domestic sale. Current regulation generally requires boilers to have a minimum efficiency of 80%. A proposed amendment to Canada's energy efficiency regulations would see the minimum required thermal efficiency of small boilers climb to 88% by 2018. The Light Commercial ENERGY STAR® Boiler program is helping ease implementation of this proposed regulation by familiarizing market participants with high efficiency technology prior to the implementation of more stringent regulation.
Description	Launched in August 2009, the Light Commercial ENERGY STAR® Boiler program is FEI and FEVI's most recent offering aimed at reducing energy consumption associated with commercial space heating. In contrast to the Efficient Boiler program this program focuses on smaller boilers with a gas input rating of 299 MBH or less. The program is designed to encourage small to medium commercial customers to install energy efficient boilers by offering a cash incentive that is calculated based on the quantity, size, and type of boiler. Typical facilities that see the installation of small boilers include:

[23] FortisBC 2010 Conservation Potential Review, Commercial Sector Report, Marbek Resource Consultants, 2011, pg 55.

<table>
<tr><td></td><td>Small to medium apartment buildings;
Small to medium office buildings; and
Schools / universities.
By encouraging the use of high efficiency boilers, the Light Commercial ENERGY STAR® Boiler program directly targets the commercial sector's most significant source of gas consumption (space heating) via one of its most widely used and longest lasting gas burning appliances (boilers). Installing such boilers today has a lasting impact by reducing gas consumption now, while paving the way for market transformation and ultimately more stringent regulation of commercial boilers. See background above for a brief review of the current regulatory context and proposed amendments.</td></tr>
<tr><td>Goals</td><td>Reduce commercial sector gas consumption by encouraging the installation and use of high efficiency (ENERGY STAR® rated) as opposed to standard efficiency boilers for space heating.
Increase year over year participation rates in view of maximizing gas savings.
Educate small to medium sized commercial customers about the advantages of energy efficient appliances and provide incentives for their adoption when necessary.
Engage the trades community and manufacturers by supporting new, energy efficient technologies.
Advance the level of skill, capacity, and understanding within trades/mechanical contractors on the correct installation practices and requirements of modern high efficiency commercial boilers. Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
Support and prepare the way for any provincial or federal regulation requiring increased boiler efficiency.</td></tr>
<tr><td colspan="2">Implementation</td></tr>
<tr><td>Administration</td><td>Program administration is handled entirely in-house by the Companies' EEC staff.
Shifting program administration to an outside service provider or dedicated program operations personnel is a requirement in 2011 in order to free up internal resources to be redirected towards new commercial program development and roll out.</td></tr>
<tr><td>Communications</td><td>www.fortisbc.com – All program information, application forms, and program terms and conditions were maintained on the Light Commercial ENERGY STAR® Boiler program webpage.
Commercial customer outreach initiative that saw the Companies call over 80,000 commercial customers to provide information on the Light Commercial ENERGY STAR® Boiler program, among others.
Program brochures describing the program specifics and how to apply were handed out at tradeshows.
Program brochures and cards describing the program specifics and how to apply were distributed to regional sales / operations centres and sales and service staff.
Approximate combined total of 2,000 pieces of cardstock / brochures</td></tr>
</table>

	distributed. • Speaking engagements / presentations describing the program at events such as: BC Apartment Owners and Managers Association semi-annual tradeshows, Rental Owners and Managers Society of BC tradeshow, NRCan "Spot the energy savings" workshop on Vancouver Island, BC Hydro PowerSmart forum, BC Hydro energy managers training session, FortisBC energy specialist training session, Vancouver Home Show, Union of BC Municipalities Whistler 2010, Business Improvement Association meetings in Victoria, Kamloops, and Kelowna, Council of Education Facilities Planners international conference. The Companies are developing a strategic communications plan for the Light Commercial ENERGY STAR® Boiler program. The plan should include: • Direct email advertising; • Additional, targeted magazine/newsletter advertising; • On-bill advertising to Rate 2 (Small Commercial) and Rate 3 (Large Commercial) customers; • Contractor and engineer information sessions; • Additional information sessions on Vancouver Island; • More leveraging of industry partner relationships; and • A program feedback session with key stakeholders.
Evaluation Strategy	The Companies believe it is too early to consider performing an in-depth analysis of the energy savings of the Light Commercial ENERGY STAR® Boiler program. Performing such an analysis requires enough participants with new boilers installed for at least one full heating season to generate statistically significant results. A study similar to that conducted on the Efficient Boiler program could be conducted after a sufficient number of program participants have had their new boilers in operation for at least one full heating season. The Companies estimate that such an evaluation could take place as early as the summer of 2012, though 2013 is more likely. Based on the final cost of the Efficient Boiler program evaluation, it is expected that an evaluation of the Light Commercial ENERGY STAR® Boiler program should cost approximately $50,000.

4.4.2.2.2 2010 Light Commercial ENERGY STAR® Boiler Program Results

As with the Efficient Boiler program, the solid net benefit-to-cost ratio of high efficiency boilers continues to generate a respectable TRC ratio, in this case of 1.6. NOTE: the TRC score for FEI new construction is based on the data from a single participant and cannot be considered representative for this segment.

Table 4-7: Light Commercial ENERGY STAR® Boiler Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	1			91	936	18%	4.8
	FEVI	-	-	-	-	-	18%	0.0
Retrofit	FEI	26	90	5	6,311	64,926	18%	1.6
	FEVI	4	12	1	646	6,915	18%	1.2
	TOTALS	31	102	6	7,048	72,777	18%	1.6

As of August 2010, the Light Commercial ENERGY STAR® Boiler program has been in market for one full year. The program garnered 56 applicants by the end of 2010, largely fulfilling expectations. Ten applications were rejected, however, as they were based on non-qualifying products (not ENERGY STAR® rated) or end uses (not space or combination space/domestic hot water heating). The rate of participation in 2010 at approximately three per month exceeds that of 2009 at two per month, suggesting time in market is essential to improving awareness, influencing the purchase decision, and increasing program participation. Forty six successful participants should be recorded once the remaining 15 applicants with pending applications submit their final documentation (i.e. proof of purchase and copy of gas permit). As with the Efficient Boiler program, all these participants have made the decision to use high efficiency boilers, thereby reducing natural gas consumption and GHG emissions. With the 31 participants who had successfully completed their application by the end of the year, the program should be responsible for a reduction of over 7,000 GJ/yr or nearly 73,000 GJs over the lifetime of the installed boilers. The annual GJ savings represent enough volume to provide gas to approximately 74 single family homes for one year. The remaining 15 applications should bring an additional savings of 3,700 GJ/yr or the equivalent of enough volume to provide gas to 40 homes. While the total incentive amount stood at just over $100,000 by year end, inclusion of all pending applications should increase the figure to approximately $140,000.

While the Companies believe the program largely achieved its overall objective (56 applicants versus 58 forecasted participants), it is clear that the Light Commercial ENERGY STAR® Boiler program suffers to a certain extent from cannibalization of participants by the Efficient Boiler program. The comparatively larger incentive combined with the availability of relatively small size boilers (down to 399 MBH input) makes the Efficient Boiler program more attractive to a certain proportion of participants. The Companies intend to revise the Efficient Boiler program during the course of 2011. At that time, consideration will be given to establishing comparative equality between the two programs' incentive structures.

As indicated in the background section above, new efficiency regulations are currently being considered by the Government of Canada (Natural Resources Canada). The proposed regulations would see the required minimum efficiency standard of smaller gas fired boiler rise from 80 percent to 88 percent by 2018. Successful installation and commissioning of high efficiency boilers requires a knowledge level beyond that of standard efficiency boilers. The Companies believe the program sends a strong signal to the market that the selection of high efficiency options should be adopted as standard practice. By encouraging the installation of high efficiency boilers today, the program is contributing to the development of the required knowledge and capacity within the market, significantly easing the implementation of new regulation over the coming years.

The simplicity of the program's structure continues to work well, requiring significantly fewer hours of administration time than the Efficient Boiler program and leading to faster turnaround times on rebate processing.

No special attempt was made in 2010 to evaluate the claimed energy savings associated with the program. The Companies believe that as most program participants had not had their boilers installed for at least one full heating season, comparative consumption data does not exist to any great extent, and any attempt to independently evaluate the natural gas savings would be futile at this time.

4.4.2.2.3 2011 Light Commercial ENERGY STAR® Boiler Program Performance Forecast

No significant changes to the cost benefit relationship of high efficiency boilers is foreseen, thus the Companies anticipate the program will continue to generate a TRC ratio in the neighbourhood of 1.6. As with the Efficient Boiler program, the Companies expect to build incrementally upon its 2010 participation as reflected in the table below.

Table 4-8: Light Commercial ENERGY STAR® Boiler Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	4	14	1	971	10,167	18%	1.6
	FEVI	-	-	-	-		18%	0.0
Retrofit	FEI	45	156	9	10,922	114,375	18%	1.6
	FEVI	10	29	3	1,615	17,261	18%	1.2
	TOTALS	59	199	13	13,509	141,803	18%	1.6

The Light Commercial ENERGY STAR® Boiler program is expected to build upon the results to 2010 and encourage even more customers to choose high efficiency boilers in 2011. While participant numbers and total natural gas savings are expected to see incremental increases over the course of the upcoming year, the underlying cost/benefit relationship of high efficiency boilers is not expected to change significantly. As such, the Companies expect the program generate a TRC score in 2011 more or less in line with what has been seen in 2010.

Raising the program's profile among the target customer groups is essential to ensuring the decision to purchase high efficiency boilers is made as often as possible. While the Companies plan to continue standard promotional efforts, a key component of this effort will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one to one with current and future commercial customers to increase participation and ease the programs application process.

4.4.2.2.4 Light Commercial ENERGY STAR® Boiler Program Summary

As with its older sibling, the Efficient Boiler program, the Light Commercial ENERGY STAR® Boiler program is expected to generate reliable value in 2011. With standard efficiency options widely available and stringent new required minimum efficiency standards on the horizon, the Companies believe it makes sense to operate the Light Commercial ENERGY STAR® Boiler program.

4.4.2.3 Efficient Commercial Water Heater Program

4.4.2.3.1 Program Overview

Efficient Commercial Water Heater Program	
Market	New Construction / Retrofit
Duration	FEI: Jul 2010 – Dec 31, 2011 FEVI: Jul 2010 – Dec 31, 2011
Incentive	<u>Storage water heaters / hot water supply boilers</u> $5 per MBH for water heaters with a thermal efficiency of 90% or higher $3 per MBH for water heaters with a thermal efficiency of 84% to 89.9% <u>On-demand water heaters</u> $2.50 per MBH for water heaters with a thermal efficiency of 90% or higher Maximum incentive is $15,000 per water heater
Partner	None
Overview	
Background	The 2006 and 2010 Conservation Potential reviews identify water heating as the commercial sector's second greatest source of natural gas consumption by volume, yet few water heaters are as efficient as they could be. Data from the Air-Conditioning, Heating, and Refrigeration Institute ("AHRI")[24] and the Consortium for Energy Efficiency ("CEE")[25], and discussions with manufacturer's reps indicate a

[24] *AHRI Database of Certified Product Performance, Water Heaters*, available at: http://www.ahridirectory.org/.
[25] "Market and Technology Characterization for Commercial Gas Water Heaters", CEE, June 2008.

	maximum combustion efficiency of approximately 80% prevails in the market. High efficiency water heating equipment with thermal efficiencies exceeding approximately 90% is available; however, the penetration rate of high efficiency technologies in the DHW market is low[26], especially for stand-alone DHW plants. Minimum required water heater efficiency is governed in BC by the British Columbia Energy Efficiency Act and the Energy Efficiency Standards Regulation, which require a minimum thermal efficiency of 80%. At present, the federal government does not regulate minimum required thermal efficiency for commercial gas water heaters. NRCan has, however, proposed implementing federal regulation of a variety of water heater types including commercial gas fired water heaters. Some proposed changes would coincide with future requirements in the United States and would see the required thermal efficiency of commercial gas fired storage type water tanks climb to 92% by 2016.
Description	The program captures energy savings associated with the heating of domestic hot water, identified in both the 2006 and 2010 Conservation Potential Reviews ("CPRs") as the second largest end use consumer of natural gas, after space heating. The program offers a financial incentive paid to the builder/developer (new construction) or account holder (retrofits or new construction) to encourage the use of high efficiency appliances in standalone DHW heating applications. Such sources include dedicated DHW high efficiency boilers and storage type water heaters. FortisBC's current boiler programs provide an incentive to generate hot water from a high efficiency source in combination Heat / DHW applications; however, a significant gap in market coverage existed prior to the launch of the Efficient Commercial Water Heater program in the case of "stand-alone" DHW systems. The program primarily appeals to commercial customers that typically exhibit high domestic hot water usage such as: • Commercial kitchens; • Multi-unit residential buildings; • Hotels/motels; and • Laundries.
Goals	• Reduce commercial sector gas consumption by encouraging the installation and use of high as opposed to standard efficiency water heaters for domestic hot water heating in commercial buildings. • Increase year over year participation rates in view of maximizing gas savings and bringing about market transformation. • Educate commercial customers about the advantages of high efficiency water heaters and provide an incentive to facilitate the purchase of high efficiency technology. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs. • Prepare the way for and support any provincial or federal regulation requiring increased water heater efficiency. • Given that one of the targets for this program is multifamily residential buildings, this program will help to satisfy clause 3(a) of the DSM Regulation,

[26] "Measures and Assumptions for Demand Side Management (DSM) Planning", Navigant Consulting, April 16, 2009.

	which states that in order to be considered adequate, a utility's plan portfolio must include measures for rental accommodation.
Implementation	
Administration	Program administration is handled entirely in-house by the Companies' EEC staff. Shifting program administration to an outside service provider or dedicated program operations personnel is a requirement in 2011 in order to free up internal resources potential to be redirected towards new commercial program development and roll out.

Communications	• www.fortisbc.com – includes a webpage with program information, application form for downloading, and program terms and conditions.
	• Commercial customer outreach initiative that saw the Companies call over 80,000 commercial customers to provide information on the Light Commercial ENERGY STAR® Boiler program, among others.
	• FortisBC Service Line newsletter containing a story outlining one participant's experience with the program and a new high efficiency water heater.
	• Web tile ads for use on partner websites (industry associations, municipalities, advocacy groups, and so on).
	• Online directory of qualifying hot water heaters to make selection of a high efficiency water heater as simple as possible.
	• Brochure: three panel brochure with application form and terms and conditions for hand out at tradeshows and delivery to the Companies' sales staff.
	• Engagement of suppliers' and manufacturers' representatives via information sessions designed to instill awareness of, and answer questions about the program.
	• Lunch and learn sessions with relevant engineering firms, plumbers. and gas fitters. The most relevant being those who deal most often with the target customer groups.
	• Speaking engagements and webpage advertisements with target organizations such as:
	    o British Columbia Restaurant and Food Services Association;
	    o British Columbia Hotel Association;
	    o Tourism Vancouver;
	    o Vancouver Hotel Association;
	    o Mechanical Contractor's Association of British Columbia;
	    o Building Operators and Managers Association;
	    o BC Apartment Owners and Managers Association; and
	    o Magazine advertisement with publications such as: HPAC Engineering magazine, APEGBC / Innovation magazine, and ASHRAE-BC Totem newsletter.
	• Direct contact with target customers, as well as their attendant suppliers, engineers, and O&M service providers is essential in the initial stages of the program.
	• Information distributed to all customer touch points including call centres and sales and service staff.

	The Companies are developing a strategic communications plan for the Efficient Commercial Water Heater program. The plan includes: • Direct email advertising; • Additional, targeted magazine/newsletter advertising; • On-bill advertising to Rate 2 and Rate 3 customers; • Contractor and engineer information sessions; • Additional information sessions on Vancouver Island; • More leveraging of industry partner relationships; and • A program feedback session with key stakeholders.
Evaluation Strategy	The Companies are currently in discussions with a restaurant chain to have condensing water heaters along with meters measuring water flow, temperature, and gas installed in several locations. The Companies will use the data gathered to confirm its savings assumptions vis-a-vis high efficiency water heaters for one of the program's key target customer groups - restaurants. The Companies would also like to perform similar evaluations in a multi-unit residential building and a hotel. A study similar to that conducted on the Efficient Boiler program could be conducted after a sufficient number of program participants have had their new water heaters in operation for a sufficient period of time. Based on the final cost of the Efficient Boiler program evaluation, it is expected that an evaluation of the water heater program should cost approximately $50,000.

4.4.2.3.2 2010 Efficient Commercial Water Heater Program Results

Thus far the overall TRC ratio of 1.1 has lined up fairly well with the expected result, though time and increased participation will confirm this as additional data becomes available. Overall participation was low in the first year, though this is a reflection of the program being launched midyear and efforts at promoting the program having not yet taken place. The program results are reflected in the table below.

Table 4-9: Efficient Commercial Water Heater Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-	-	-	-	5%	-
	FEVI	-	-	-	-	-	5%	-
Retrofit	FEI	7	15	3	592	4,607	5%	1.1
	FEVI	2	3	1	144	1,155	5%	0.9
	TOTALS	9	18	4	736	5,762	5%	1.1

The Companies rolled out the Efficient Commercial Water Heater program in late July 2010. Overall program participation in 2010 was modest, though the Companies believe this is to be expected. The program went live comparatively late in the year, and it generally takes at least one year in market for new programs to gain traction. Moreover, encouraging the program's key target customers (restaurants, hotels, and multi unit residential buildings or "MURBs") to choose high efficiency options for water heating will involve a significant amount of working one-on-one with prominent customers to obtain buy-in and generate success stories that may be used to convince others to adopt high efficient technology. The Companies simply did not have the opportunity to begin this work in 2010. Even so, greater participant numbers are expected in 2011, the first month of which saw eight applicants; nearly as many participants as the program had in 2010.

The minimum required water heater efficiency in BC for commercial water heaters is currently at 80 percent. NRCan has, however, proposed implementing a new federal regulation that would impact commercial gas fired water heaters. The proposed changes would see the required thermal efficiency of commercial gas fired storage type water tanks climb to 92 percent by 2016. Though the regulation is as yet only a proposal, it is clear regulation is being actively considered. The Efficient Commercial Water Heater program is in operation today, helping to build awareness and capacity in the marketplace and pave the way for future regulation when implemented. The Companies believe the program will provide invaluable assistance to the government's objectives in this regard.

The program turns in TRC scores generally above 1.0, indicating that participants are cost effectively reducing their natural gas consumption; however, caution must as yet be used when interpreting the values indicated in the table above. The number of participants and the resultant amount of data collected does not yet allow the Companies to generate results with any degree of statistical significance. Further, the TRC score for the initial year is burdened by program development expenses such as website and program collateral development.

4.4.2.3.3 2011 Efficient Commercial Water Heater Program Performance Forecast

As can be seen in the table below, the Companies expect increased participation in 2011 as the market becomes aware of the program and more customers are effectively encouraged to choose high efficiency water heaters. The primary driver of this increased awareness and program uptake must be the Companies' outreach and promotions activities. Thus far, only a limited effort has been made to promote the technology and program to market participants. The program's TRC score should benefit slightly as program development costs are not incurred in 2011 and increased participation helps cover general program administration costs. Program performance forecasts for 2011 are provided in the table below.

Table 4-10: Efficient Commercial Water Heater Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	3	7	2	254	2,656	5%	1.2
	FEVI	1	2		85	676	5%	1.3
Retrofit	FEI	45	99	9	3,805	39,842	5%	1.2
	FEVI	5	7	2	361	2,884	5%	1.0
	TOTALS	54	116	13	4,504	46,058	5%	1.2

Central to the promotion of the program will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the program's application process.

Currently, the Companies are actively collaborating with a restaurant chain and are seeking hotels and MURBs to work with to install new high efficiency water heaters, monitor the results, and produce success stories to be used to promote the high efficiency appliances to other potential program participants. The Companies believe working directly with restaurant and hotel chains, as well as apartment and condo associations to reinforce the positive benefit of high efficiency water heaters will be key to the program's success. High efficiency water heaters are relatively new compared to boilers and many who could benefit from their use either don't know they exist or have concerns about their operation. Working with several high profile customers and promoting their success is expected to change this mindset. Several MURBs opt for indirect water heaters and the Companies are looking to include these in the program to help the market.

The Companies are also eager to leverage the relationship currently being built with the Green Table Network Society (see Spray Valve program, Section 4.4.3.1) to encourage the use of high efficiency water heaters and generate program participants from the commercial food service industry.

4.4.2.3.4 Efficient Commercial Water Heater Program Summary

As the marketplace becomes more aware of the program, the Companies expect this awareness to effectively encourage more customers to install high efficiency in place of standard efficiency water heaters, leading to increased participation in 2011. The program's simple structure should help to keep administrative spending low over the long run and also contribute to an overall positive TRC score, similar to the Light Commercial ENERGY STAR® Boiler program.

4.4.2.4 Energy Assessment Program

4.4.2.4.1 Program Overview

Energy Assessment Program	
Market	Retrofit
Duration	FEI: 2001 – Dec 31, 2011 FEVI: May 2009 – Dec 31, 2011
Incentive	A walkthrough energy assessment and written report – a $1,200 value, funded entirely by the Companies
Partner	None
Overview	
Background	N/A
Description	The Energy Assessment program has been in operation since 2001 with minor modifications made over the years. This program is designed to identify inefficiencies in natural gas energy consumption and provide recommended solutions in the following sectors: condominiums and apartments, food processors, greenhouses, hospitals, hotels, industry, offices, recreation centres, restaurants, schools, warehouses, and wood products. Inefficiencies are identified at the participant's facilities via an onsite walkthrough assessment by an energy efficiency consultant. The consultant then produces a report, describing the observed inefficiencies and outlining proposed energy savings measures that may be implemented to reduce gas consumption. The Companies then forward the report to the participant.
Goals	• Enable and encourage commercial customers to reduce gas consumption by identifying sources of high gas consumption within their facilities and proposing implementable measures aimed at reducing consumption. • Educate commercial customers about gas use within their own facilities and the steps they can take to minimize consumption. • Foster a culture of conservation among commercial sector customers, including MURBs and institutional and manufacturing customers, by assisting them with reviewing their energy consumption. • Where applicable, direct participants to available incentive programs including FortisBC's existing boiler programs. • Maintain a program TRC ratio greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
Implementation	
Administration	Administration of the Energy Assessment program is handled in-house by the Companies' DSM staff as well as the external service provider Environ.
Communications	• www.fortisbc.com – the Companies maintained a webpage dedicated to the program that included program information, application forms, and program terms and conditions. • Brochure: three panel brochure with program information and terms and

	conditions for hand out at tradeshows and use by the Companies' sales and key accounts staff. • Speaking engagements / presentations describing the program at events such as: NRCan "Spot the energy savings" workshop on Vancouver Island, BC Hydro PowerSmart forum, BC Hydro energy managers training session, FortisBC energy specialist training session, Business Improvement Association meetings in Victoria, Kamloops, and Kelowna, and the Council of Education Facilities Planners international conference. • Direct promotion of the program by the Companies' key accounts staff.
Evaluation Strategy	An initial evaluation study was completed in 2008. The Companies completed a second evaluation study in early 2010 based on participation from July 2007 through July 2009. This study provided additional insight into the program's performance and allowed the Companies to refine the data underlying the savings assumptions. The study compared expected gas usage of program participants to actual usage post assessment to quantify energy savings. Phone interviews where then carried out to account for changes in occupancy or business activity that may have had a bearing on the observed post assessment energy consumption. Data from the latest evaluation study suggests participants save on average 688 GJ/yr after participating in the program. This is a significant increase over the previous study that suggested 299 GJ/yr of savings. It must be noted that the average savings in any particular round of evaluation is heavily influenced by the number and size of manufacturing sector participants, who account for the majority of the natural gas savings. For this reason, the Companies believe using the average of the two studies represents a prudent estimation of the natural gas savings in any particular period. Furthermore, the Companies have reviewed participants in the Energy Assessment Program over a 2 year period versus participants in the Companies' other incentive programs to eliminate any possible double counting of savings.

4.4.2.4.2 2010 Energy Assessment Program Results

The Energy Assessment program maintains a solid TRC ratio of 2.5 overall, thanks largely to the ultimate implementation of recommended measures by manufacturing companies. Program results for 2010 are provided in the following table.

Table 4-11: Energy Assessment Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	FEI	55	66	25	17,446	17,446	35%	2.4
	FEVI	13	16	2	4,124	4,124	35%	2.9
	TOTALS	68	82	26	21,569	21,570	35%	2.5

The Companies continued to operate the Energy Assessment program in 2010 as it had been operated in previous years and the program exceeded expectations in terms of participation. Vancouver Island especially saw a significant increase in assessments performed, jumping from zero in 2009 to 13 in 2010. The program has effectively delivered facility specific energy assessments to all participants, encouraging them thereby to reduce their natural gas consumption. The latest program evaluation study demonstrates that participants do in fact implement recommended measures post assessment, though the proportion of implementation varies among the commercial market segments.

The program maintains a strong TRC score, largely due to the significant energy savings of the manufacturing sector participants who implement energy saving measures after receiving their Energy Assessment. The latest evaluation study asserts that:

> *"…this program was most effective amongst manufacturing companies. These respondents were responsible for 92 percent of the total GJs reduced in this study while representing only 23 percent of the total program participant premises. In conclusion, these findings clearly indicate that the program was most effective amongst manufacturing clients."*

While the evaluation study suggests the Companies should focus on offering energy assessments primarily to manufacturing companies and large institutional customers who are responsible for most of the savings, the Companies believe that for the time being it is important to offer the program to as many potential participants as possible. The Energy Assessment program allows the Companies to help foster a culture of conservation among commercial customers by visiting their facilities directly and helping educate them on their gas use. The program is also an important "first contact" that can lead to subsequent participation in the Companies' other incentive programs where applicable.

4.4.2.4.3 2011 Energy Assessment Program Performance Forecast

The Energy Assessment program is expected to perform in 2011 much as it did in 2010, though the TRC ratio will benefit somewhat as program evaluation costs will not be incurred in the new year. Program performance forecasts for 2011 are provided in the following table.

Table 4-12: Energy Assessment Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	FEI	61	73	27	19,190	19,190	35%	2.7
	FEVI	14	17	2	4,536	4,536	35%	3.3
	TOTALS	75	90	29	23,726	23,726	35%	2.8

It is expected the program will perform in 2011 much the same as in 2010, while building incrementally on participation numbers and educating additional customers on their energy use and the benefits of energy efficiency. Additional promotion of the program to light industrial and manufacturing customers will take place. Central to this will be the role played by the Companies' new energy solutions managers. The energy solutions managers will be increasing awareness of and participation in Energy Efficiency and Conservation programs by actively participating in industry associations, hosting workshops for commercial customers and seminars for energy managers, and educating small commercial customers through the Service Line newsletter. They will also work one-on-one with current and future commercial customers to increase participation and ease the programs application process.

4.4.2.4.4 Energy Assessment Program Summary

The Companies believe the Energy Assessment program is a valuable tool that is, and continues to be, used to foster an awareness of energy use and energy efficiency issues among commercial customers, raise awareness of and participation in other incentive programs, and effectively encourages participants to reduce energy consumption. As such, the program remains an important component in helping to lay the foundation for longer term market transformation.

4.4.2.5 Public Sector Energy Conservation Agreement ("PSECA") Initiative

4.4.2.5.1 Program Overview

Public Sector Energy Conservation Agreement ("PSECA") Initiative	
Market	Public Sector Retrofit
Duration	FEI: Jul, 2010 – Jul, 2012 FEVI: Jul, 2010 – Jul, 2012
Incentive	The Companies made use of several existing funding models to provide incentives tailored to each project's specific situation, with all incentives falling under the umbrella of the PSECA initiative. Thus, while incentives where determined using the most appropriate program model, participants are counted under the PSECA initiative, not in the programs whose funding model was applied. Refer to: Efficient Boiler Program Efficient Commercial Water Heater Program Commercial Custom Design Program
Partner	Ministry of Environment, BC Hydro, Solar BC

<table>
<tr><th colspan="2">Overview</th></tr>
<tr><td>Background</td><td>The first PSECA was created in 2007 as a partnership between BC Hydro and the Government of BC. Budget 2008 committed $75 million over three years to help public sector organizations reduce provincial GHG emissions, energy consumption, and operating costs, as well as support government in achieving its goal of carbon neutrality. The first two rounds of PSECA's have achieved annual energy cost savings of close to $7.4 million, GHG emissions reductions of over 18,700 tons, and conservation of 38.6 GWh of electricity. The latest iteration of PSECA is the third round and marks the first time the Companies have been involved.

Eligible public sector organizations include all organizations listed in the Government Reporting Entity ("GRE"):
Ministries and agencies;
Boards of Education;
Universities and colleges;
Health authorities; and
Crown corporations.</td></tr>
<tr><td>Description</td><td>In 2010, the Companies participated in the Public Sector Energy Conservation Agreement, operated by the Climate Action Secretariat, a division of the Ministry of Environment. The PSECA initiative represents a major undertaking for the commercial program area staff during the second half of 2010. The Companies worked in partnership with the Climate Action Secretariat, BC Hydro, and Solar BC to encourage public sector organizations to reduce energy consumption and GHG emissions by offering incentives for the completion of qualifying projects.

Typical projects included:
Boiler upgrades;
Building automation controls;
Water heater upgrades; and
Heat recovery measures.</td></tr>
<tr><td>Goals</td><td>To contribute to the Province's objective of a 33% reduction in GHG emissions from 2007 levels by 2020.
To encourage public sector organizations to reduce natural gas consumption.</td></tr>
<tr><th colspan="2">Implementation</th></tr>
<tr><td>Administration</td><td>Administration was primarily handled in-house by FortisBC staff, including receipt and review of energy studies and communication with the Climate Action Secretariat and program partner BC Hydro.</td></tr>
<tr><td>Communications</td><td>External communications were managed by the provincial government. Refer to http://www.env.gov.bc.ca/cas/mitigation/pseca.html.</td></tr>
<tr><td>Evaluation Strategy</td><td>All projects are reviewed both before and after completion. Initially, the Companies reviewed all submitted energy studies to assess the validity of the claimed natural gas savings. On completion of a project, the participant must submit the required installation documentation. Prior to paying the incentive, the Companies perform an on-site audit of all projects to ensure equipment has been installed and is functioning</td></tr>
</table>

	as initially proposed. At the Companies' discretion, some projects may be subjected to a measurement and verification ("M&V") protocol, whereby metering equipment is installed to measure and verify the energy savings.

4.4.2.5.2 *2010 PSECA Initiative Results*

The Companies' involvement with the Public Sector Energy Conservation Agreement afforded an excellent opportunity to invest in high quality, long term energy saving measures, as well as demonstrate the leverage advantage of working with partners. While the effort consumed much time that would otherwise have been devoted to new program development and roll out, the trade-off generated a program with a TRC score of 2.3 for incentive dollars committed in 2010. Program results for 2010 are provided in the table below.

Table 4-13: PSECA Initiative Program Actuals

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-		-		-	
	FEVI	-	-		-		-	
Retrofit	FEI	15	531	11	18,222	163,420	0%	2.4
	FEVI	13	297	5	11,706	107,935	0%	2.2
	TOTALS	28	827	15	29,928	271,355	0%	2.3

As noted above, the PSECA initiative represents a major undertaking during the second half of 2010. The Companies believe, however, that the results to date were well worth the effort. By the end of the year the Companies committed to providing nearly $830,000 for energy saving measures at 28 locations to program participants who successfully complete the approved measures. When complete, these measures are expected to reduce natural gas consumption by approximately 30,000 GJ/yr, or enough to provide natural gas to 315 single family homes during the same time period.

The TRC score for the PSECA initiative is quite robust, which the Companies take as an indication of the high quality of the energy saving projects approved for funding.

4.4.2.5.3 *2011 PSECA Initiative Performance Forecast*

In 2011 the Companies expect to provide additional EEC incentive dollars to successful participants in a second round of PSECA funding. This second tranche consists of projects designed to reduce natural gas consumption and greenhouse gas emissions of K through 12 schools.

Table 4-14: PSECA Initiative Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-		-		-	
	FEVI	-	-		-		-	
Retrofit	FEI	12	800	24	30,830	322,840	0%	0.7
	FEVI	2	208	9	5,497	58,745	0%	1.0
	TOTALS	14	1,008	33	36,327	381,585	0%	0.7

Among this second group of projects are 12 central thermal plant upgrade projects, 4 of which consist of conversions to open loop type geoexchange heat pump systems with gas boiler backup. These will significantly reduce natural gas consumption and greenhouse gas emissions at each of the affected facilities.

Throughout 2011 and into 2012 FortisBC staff will expend a considerable amount of time and effort to inspect completed PSECA projects to ensure the approved energy saving measures have been built as described and are fully complete and operational prior to issuing payment. This will ensure incentives are only paid out where warranted.

Further to this, in 2013, after all the approved energy saving measures have been installed for a minimum of one full heating season, FortisBC staff will review the program's actual energy savings versus the claims of the energy studies. The results of the review will be used to refine the custom design program.

4.4.2.5.4 PSECA Initiative Summary

The combined 2010 and 2011 PSECA program activity will generate an overall TRC result above 1.4 by the time work in the program is finalized in late 2011 or early 2012. The Companies believe the PSECA initiative, offered in collaboration with the Climate Action Secretariat and BC Hydro, will successfully encourage public sector organizations to significantly reduce natural gas consumption and GHG emissions.

4.4.2.6 Fireplace Timers Pilot Program

4.4.2.6.1 Program Overview

Fireplace Timers Pilot Program	
Market	Retrofit
Duration	FEI: Nov 1, 2009 – Dec 31, 2011 FEVI: N/A
Incentive	Provision of fireplace timer at no charge, plus $30 per timer towards the cost of installation.

<table>
<tr><td>Partner</td><td>None</td></tr>
<tr><th colspan="2">Overview</th></tr>
<tr><td>Background</td><td>According to a 2005 report done by Habart & Associates called Impact of Terasen Gas* Pilot Fireplace Program (2004), a decorative gas fireplace consumes approximately 14.9 GJ/yr of natural gas.
Based on information contained in the Terasen Gas* 2008 REUS, only 12% of decorative fireplaces are used for heating purposes and 55% of these units are used for ambiance. This would seem to indicate that a significant amount of energy could be saved by encouraging consumer use of a fireplace timer to turn off their fireplace after a specified period of time.
In a 2003 study completed by FEI at Strata Plan LMS 1685 located at 8420 Jellicoe Street in Vancouver, it was found the installation of the fireplace timer significantly reduced the gas consumed by the strata. The strata embarked on a retrofit project in 2002 as a means to reduce their gas consumption. In this study, it was determined that by installing a fireplace timer in suites, gas savings of 6 GJ/yr were achieved. A testimonial by Strata Plan LMS 1685 was later released in June 2003 validating these results.
*At this time the Company operated under the name Terasen Gas.</td></tr>
<tr><td>Description</td><td>The purpose of this pilot program is to study the effect on gas consumption of installing electronic programmable timers on decorative gas fireplaces in MURBs. It is believed the timers will reduce instances of customers leaving gas fireplaces burning longer than is actually needed. The pilot is offered in FEI’s Lower Mainland service territory. The timers are only installed in units where the fireplace is not the primary heating source.</td></tr>
<tr><td>Goals</td><td>The main purpose of this pilot program is to determine what the actual energy savings are from fireplace timers. Additionally, the pilot seeks to evaluate:
• Potential difficulties with offering a full program in the awkward legal context of strata corporations;
• Whether or not the market has sufficient installation capacity to run a full program; and
• To enroll 1,000 participants, each saving 3 GJ/yr for a total of 3,000 gross annual savings for the program.</td></tr>
<tr><th colspan="2">Implementation</th></tr>
<tr><td>Administration</td><td>Program administration entirely in-house by the commercial EEC team.</td></tr>
<tr><td>Communications</td><td>For the pilot, communications is achieved by a webpage on the Company’s website in addition to being promoted in person to applicable customers.</td></tr>
<tr><td>Evaluation Strategy</td><td>FEI will review the gas consumption of the participating buildings prior to the installation of fireplace timers. This data, obtained from the FEI billing system, will establish the baseline gas consumption.
After the pilot is completed and reviewed, a larger program running over multiple years will be considered and offered throughout the Companies’ service territories.</td></tr>
</table>

4.4.2.6.2 Fireplace Timers Pilot Program Results

The Fireplace Timer Pilot program has garnered some participation, though the requirements of the pilot study make gaining participants among strata properties a challenge; however, the

Companies continue to expect the pilot program will confirm a positive cost benefit ratio for the measure as indicated in the table below.

Table 4-15: Fireplace Timers Pilot Program Results

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-		-	-	0%	-
	FEVI	-	-		-	-	0%	-
Retrofit	FEI	195	10		585	2,374	0%	2.3
	FEVI	-	-		-	-	0%	-
	TOTALS	195	10	-	585	2,374	0%	2.3

This pilot program was launched in late 2009 and operated throughout 2010. While the Companies ultimately anticipate the measure will deliver a strong TRC performance[27], participation in the pilot program is not currently at the desired level of 1,000 timers installed; however, the Companies do not consider this to be a critical issue. There are two items that hinder program uptake. First, in order to ultimately quantify the impact of the fireplace timers on the overall building consumption, and thereby determine the natural gas savings per timer, the pilot program requires essentially all of any given building's decorative fireplaces to be equipped with timers. It is difficult for strata corporations to achieve this requirement, as each individual dwelling unit holder legally decides what happens within each unit. Thus essentially all of the unit holders must agree to participate in the program and have timers installed in their units before a strata can be accepted into the program. Secondly, as this is a pilot program, comparatively little effort has been expended on promoting this pilot program in 2010. The Companies have sought assistance from industry partners but to date additional participants have not been forthcoming.

It must be noted that once the savings of the fireplace timers have been established, and the positive cost benefit ratio has been confirmed, a full program will not require all of the units in the building to be equipped with fireplace timers in order to participate. Any such full scale program will not face the same difficulties in generating participation.

4.4.2.6.3 Fireplace Timers Pilot Program Performance Forecast

Based on current applicants to the program (those who have submitted an application but have not finalized the remainder of the requirements) the Fireplace Timer Pilot program will increase its participation in 2011 to a level that may allow the Companies to proceed with the savings evaluation. The performance forecast for the program is provided in the following table.

[27] NOTE: The TRC ratio presented in the table is based on the cost benefit assumptions underlying the pilot program business case.

Table 4-16: Fireplace Timers Pilot Program Performance Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	-	-	-	-		0%	
	FEVI	-	-	-	-		0%	
Retrofit	FEI	400	20		1,200	4,901	0%	2.5
	FEVI	30	2		90	370	0%	2.0
	TOTALS	430	22	193	1,290	5,271	0%	2.5

It is expected that the greater part of the target number of installations will be installed by the end of 2011. As of January 2011 the Companies had an additional 247 potential timer installations recorded. The Companies require only that the participants accept the full terms and conditions and ensure a sufficient number of dwelling unit holders agree to participate in order to include these as participants.

After a sufficient number of timers have been installed the Companies believe analysis work can begin and may generate meaningful results as to the savings per timer. If such results are reasonably consistent it may not be required to have all of the originally projected 1,000 timers installed as part of the pilot program. Analysis of the results could begin after the winter of 2011 / 2012, when a sufficient number of fireplace timers have been installed for a least one full heating season.

4.4.2.6.4 Fireplace Timers Pilot Program Summary

The aim of this program is to reduce the amount of natural gas used for decorative fireplaces and ultimately change the behaviour of the end user. By encouraging them to control the amount of time the fireplace is on, they are also becoming more aware of their energy use and ultimately their building’s energy use. The timers provide options for running times of 30 minutes, 60 minutes, or 120 minutes before the fireplace turns off automatically. If by implementing this measure a building can save approximately three GJs per unit, that would add up to significant financial savings over several years.

4.4.2.7 Radiant Tube Heaters Pilot Program

4.4.2.7.1 Program Overview

Radiant Tube Heaters Pilot Program	
Market	Retrofit
Duration	FEI: To be determined FEVI: To be determined

Incentive	Established independently for each participant and governed by the cost benefit ratios specific to each site.
Partner	None
Overview	
Background	Radiant tube heaters use infrared energy to heat buildings. Infrared energy is a form of electromagnetic radiation, and heats objects directly, instead of indirectly via the medium of heated air. Occupants feel comfortable without the need to heat all the air in the space to 24° C. In comparison, unit heaters heat air and comfort is maintained by keeping the air warm to avoid heat loss of occupants. Warm air is difficult to control in many commercial settings such as manufacturing facilities, warehouses, garages, workshops, barns and sheds, and so on. The warm air rises to the ceiling or gets blown out the door, resulting in significant inefficiencies and increased gas use as occupants turn up the thermostat to compensate.
Description	The purpose of this pilot study is to assess the gas savings potential of radiant tube heaters versus unit heaters used for space heating in commercial facilities. The data gathered via this study will contribute to the development of a full scale program offering should radiant tube heaters return a positive TRC ratio. It is suspected that radiant tube heaters could achieve significant energy savings when used in place of unit heaters in manufacturing, warehousing, or similar applications.
Goals	• To study the effectiveness of infrared heating technology and validate or modify the energy savings assumptions used in this business case. • Similarly, to validate or modify the measure cost assumptions used in this business case. • To gain insight into additional benefits (i.e. occupant comfort, reduced noise, and so on) that accrue to users of radiant tubes.
Implementation	
Administration	To be determined
Communications	None
Evaluation Strategy	The results of the pilot study shall be evaluated as follows: A pre/post comparison of gas consumption will be used to establish the energy savings. The facility's weather normalized pre-installation gas consumption will define the baseline consumption to which the new system's performance will be compared. Gas sub meters will be installed to independently collect consumption data for the truck bays and the office/administrative areas over the course of at least one full heating season. This data will then be compared to the baseline to establish the actual energy savings. Additional benefits such as increased occupant comfort will be assessed via a brief interview with the owner/occupants after one full heating season.

4.4.2.7.2 Radiant Tube Heaters Pilot Program Results

In 2010, the Companies set up a pilot program to study the effectiveness of radiant tube heaters at reducing natural gas consumption due to space heating. Several other natural gas utilities in North America provide incentives to encourage the use of radiant tube heating instead of more conventional forced air unit heaters. It is believed radiant tube heaters would work well in BC's climate, though preliminary results from the pilot will not be available before January 2012

4.4.2.7.3 Radiant Tube Heaters Pilot Program Performance Forecast

As of the writing of this report, the pilot program has one active participant, located in the Interior of British Columbia. The Companies are actively seeking additional participants in the interior and coastal regions of the province. The table below presents the estimated data[28] associated with the initial participant. Additional estimates can be made as suitable potential participants are identified.

Table 4-17: Radiant Tube Heaters Pilot Program Performance Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
Retrofit	FEI	1	3	7	275	2,880	0%	1.5
	FEVI	-	-	-	-	-	0%	0.0
	TOTALS	1	3	7	275	2,880	0%	1.5

In 2011, radiant tube heaters will be installed in up to five locations in the province. Data will then be collected over the winter of 2011 / 2012 and used as support for launching a full scale program, should the cost benefit results prove positive.

4.4.2.7.4 Radiant Tube Heaters Pilot Program Summary

The Companies suspect radiant tube heaters may be an effective way to reduce natural gas consumption for space heating in applicable locations. The Radiant Tube Heaters Pilot program will allow the Companies to gather empirical data specific to the climate zones in BC, while investigating available research from other jurisdictions. Should the results prove positive the Companies will proceed with a full scale prescriptive program development.

4.4.3 PROGRAMS IN DEVELOPMENT

4.4.3.1 Spray Valve Program

4.4.3.1.1 Program Overview

Spray Valve Program	
Market	Retrofit
Duration	FEI: Jan 31, 2011 – Dec 31, 2011

[28] NOTE: The TRC ratio and energy savings presented in the table are based on the estimates underlying the acceptance of the initial location into the pilot program.

	FEVI: Jan 31, 2011 – Dec 31, 2011
Incentive	Direct install of low flow pre rinse spray valves
Partner	Green Table Network Society ("GTNS"): Founded in 2007, GTNS is based in Vancouver, BC. GTNS is a group of restaurant professionals, joined by the people who supply and support them, who are making a conscious commitment to sustainability in commercial food service establishments.
Overview	
Description	The Companies are currently developing another low flow pre rinse spray valve install program. Similar to previous pre rinse spray valve programs, the proposed program is designed to achieve energy savings by directly installing new, low flow pre rinse spray valves in food service establishments ("FSEs") within the Companies' service territories. These pre rinse spray valves will be installed in FSEs that consume domestic hot water from gas-fired water heaters only. Unlike previous spray valve programs, the Companies propose to partner with an external program operator (GTNS) for program outreach and delivery. The partner will install all spray valves on behalf of FortisBC and will be responsible for data collection, the inventory of spray valves, and general administration of the program.
Goals	• To install up to 300 spray valves province wide over the course of one year or to a maximum of $25,000. • To achieve gas savings of approximately 2,650 GJs/yr and save our customers approximately $24,000 in annual gas expenditures.[29] • To raise awareness of energy efficiency, especially as it pertains to water heating, among FEI and FEVI's commercial cooking customers, with a view of increasing participation in the Companies' commercial programs. • To establish and evaluate a working relationship with GTNS with a view to partnering with them again on future incentive programs targeted at commercial FSEs.
Background	Low flow pre rinse spray valves use approximately 50% less water than standard models[30], significantly reducing the volume of heated water used in dishwashing operations. This in turn reduces the energy demands placed on the hot water system, and thereby the overall energy consumption of a given facility. Pre-rinse spray valves ("PRSVs") are commonly used in restaurants, hotels, schools, grocery stores, and hospitals to rinse down plates, pots, and pans.
Implementation	
Administration	GTNS will be administering the program and keeping track of all participants. They will then submit all information on the participants back to FortisBC. • The customer will contact GTNS directly to request a new valve. GTNS will set up appointments to visit the establishment and directly install a pre rinse spray valve. • GTNS will be required to record hot and cold water temperatures, pre- and post-installation flow rates, and estimate usage hours, amongst other data points, and enter this data into a database and calculate energy savings on a per-establishment basis. • GTNS will provide weekly updates on participants and program information as outlined in the agreement.

[29] $24,000 is based on an average of FEVI & FEI Rate 2 and Rate 3 customers as of January, 2011.
[30] FortisBC 2010 Spray 'n' Save Victoria Program Results.

	• GTNS will submit invoices to FortisBC as outlined in the agreement between FortisBC and GTNS. FortisBC will then reimburse GTNS for each valve installed in establishments using natural gas to generate hot water, to a maximum of $85 per valve, enough to cover the cost of the valve. GTNS is responsible for the installation cost of the measure.
Communications	The program's requirement for communications material or collateral is relatively light. Program promotions and participant uptake is driven primarily by GTNS. As such communications / collateral requirements were limited to: 1. Participant consent form; 2. Information card to hand out to participants or potential participants; and 3. A website to inform potential participants about the program and allow them to request the installation of low flow spray valve(s) by directing them towards the GTNS contact page.
Evaluation Strategy	GTNS will provide to FortisBC brief weekly updates via email on the number of new valves installed and advise if any issues have arisen with the program in the interim period since the last update. No later than four months after the completion of the program, GTNS will compile a final written report identifying any challenges or barriers to FSE participation and GTNS' perspective on any aspects of the program that worked especially well and any aspects that can be improved. These results will be compared to those of the Okanagan Spray Saver evaluation and the Victoria Spray Saver program for confirmation and verification of savings.

4.4.3.1.2 2011 Spray Valve Program Performance Forecast

Based on the very solid TRC performance noted in the previous iterations of the low flow pre rinse spray valve program, the Companies expect this version of the program will be a strong performer as well. Note the TRC score presented in the table below is not as strong as presented in section 4.4.1.1. Under this version of the program the Companies are working with a partner and are not in control of all costs. To be conservative, the maximum estimated measure cost of $130 per installed valve has been used in the TRC analysis until such time as the actual installation cost incurred by the partner is determined.

Table 4-18: Spray Valve Program Forecast

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
New Const	FEI	4			32	2,252	12%	1.9
	FEVI	-	-	-	-	-	12%	0.0
Retrofit	FEI	235	20	3	1,861	7,554	12%	2.4
	FEVI	55	5	1	434	1,792	12%	2.4
	TOTALS	294	25	3	2,327	11,598	12%	2.3

The Companies intend to offer a direct install, low flow pre rinse spray program once again in 2011. The program will have several key differences in comparison to its predecessor initiatives, which the Companies believe could improve performance and extend the reach of the energy efficiency message within the commercial food service market segment. The Companies propose to partner with GTNS that will be responsible for the program operations, including overseeing the provision and installation of the pre rinse spray valves in qualifying locations. GTNS will use its network of contacts in the food service industry to generate program participants throughout the province. Further, GTNS will promote FortisBC's other commercial incentive programs wherever applicable. In practice, this will mean significant additional customer direct promotions of the Efficient Commercial Water Heater program to one of its key target groups. For their part, the Companies will pay for the new spray valves and provide promotional materials and exposure for the program at all relevant opportunities.

While the initial forecast is for approximately 300 new spray valves to be installed, the Companies will extend the agreement to allow for the installation of additional valves should the initial collaboration prove to be positive and productive. The initial run of the program should allow the Companies to invest approximately $25,000 in natural gas efficiency among commercial food service establishments.

The Companies believe that despite the strong value proposition of low flow pre rinse spray valves, the dynamics of the food service industry make it necessary to operate a DSM program in order to capture the potential natural gas savings. The commercial food service business tends to be exposed to significant volatility, making "cheapest first cost" a critical purchase decision criteria for any item that is not critical to customer service. Food service establishments typically lack the time or resources to research energy saving options or understand the benefits provided. Though low flow spray valves pay for themselves relatively quickly, the ultimate magnitude of the dollar savings per any single valve is unlikely to move most potential beneficiaries to action. A utility funded DSM program makes it easy and straight forward for participants to save natural gas by effectively eliminating both the effort and risk that potential participants would normally associate with the selection of high efficiency options.

The spray valve program will also play an important role in introducing a new concept to the food service industry, namely that energy is a variable cost. The Companies believe most food service establishments consider energy to be a fixed cost and that changing this mindset is essential to ultimately bringing about market transformation. In this light, the Companies believe low flow pre rinse spray valve programs are an essential first step that will lead to greater energy savings down the road.

4.4.3.1.3 Spray Valve Program Summary

The program is initially expected to install approximately 300 low flow pre rinse spray valves in locations that would otherwise be using standard flow rate sprayers, generating significant natural gas savings as a result. The Companies thus believe the program will successfully deliver tangible natural gas GJ savings, as well as the non-tangible benefit of raising energy awareness in the commercial food service sector. Furthermore, the program will allow the Companies to develop and evaluate a business relationship with a potentially valuable partner in the effort to achieve market transformation in the commercial food service sector. Finally, the proposed program and partnership with GTNS represents an excellent opportunity to raise awareness and encourage greater uptake of the Efficient Commercial Water Heater program and subsequent program offerings within this sector.

4.4.3.2 Commercial Custom Design Program

4.4.3.2.1 Program Overview

Commercial Custom Design Program	
Market	New Construction / Retrofit
Duration	FEI: To be determined FEVI: To be determined
Incentive	• All energy conserving measures must exceed a TRC score of 1.0 to be eligible for an incentive • Incentives calculated as $5/GJ saved on the net present value of the natural gas savings over 50% of the estimated measure life to a maximum of 10 years • Incentives not to exceed 100% of the measure's incremental cost
Partner	BC Hydro
Overview	
Background	The Companies have historically offered incentives to commercial customers via prescriptive programs only. The prescriptive method assigns energy savings and incentive amounts to specified energy savings measures based on a generalization of how the measure will perform when installed. Many commercial customers have potential energy saving projects that are bigger and more complex than can be addressed in a prescriptive program due to the complexity and custom designed nature of their mechanical systems. A program to allow the Companies to encourage the implementation of these projects is necessary to capitalize on the natural gas saving opportunity they represent. The Commercial Custom Design program will meet this need by providing incentives tailored to suit the energy saving measures specific to each individual participant's project.
Description	The program seeks to capture energy savings associated with measures (i.e. technologies, systems, or operational strategies) that are otherwise difficult to incent as part of a prescriptive program because they are complex, and may include multiple measures with interactive effects in one project. This custom program will capitalize upon the creative potential of the marketplace, and help foster expertise in advanced energy efficiency design in BC. It is expected that most participants will be from sectors such as: 1. Large commercial facilities; 2. Large multifamily residential buildings; 3. Institutional and government; 4. Agriculture; and 5. Manufacturing (where measures address space or water heating). For such groups, the potential to achieve gas consumption savings by incorporating measures specifically engineered to suit their particular situation and needs is

<table>
<tr><td></td><td>expected to significantly surpass what can be accomplished via a prescriptive program. These may include measures that will:
• Make use of alternative energies, with gas backup
• improve building envelope performance;
• use more efficient gas burning equipment or systems;
• recover and reuse energy that is currently lost;
• capture and use solar energy for heating air or water;
• reduce the rate of energy consumption by systems or equipment in low occupancy periods; and
• eliminate unnecessary energy usage by shutting off idling or unneeded equipment
Energy saving measures will be presented to the Companies for review, in an energy study format prepared by a qualified consultant. Qualified consultants are engineering professionals, retained by the program participants, who meet the technical proficiency and experience requirements of the Companies.</td></tr>
<tr><td>Goals</td><td>• To capture energy savings from otherwise difficult to incent measures including whole building measures.
• To foster additional capacity and design expertise with custom energy savings measures in BC.
• Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.</td></tr>
<tr><td colspan="2">Implementation</td></tr>
<tr><td>Administration</td><td>Handled by in-house EEC staff, BC Hydro Power Smart staff, and outside service providers where necessary.</td></tr>
<tr><td>Communications</td><td>Promotion of the custom program will be driven primarily via direct contact with target participants by the Companies’ staff or the program’s qualified consultants. Target customers should include:
o Health care administrators;
o Education administrators;
o Large institutional property managers (i.e. Nexacor, Profac, and so on);
o Municipalities – facilities and/or energy managers as well as municipal planners;
o Provincial government - facilities and/or energy managers; and
o Builders and developers.
Additional promotion via:
▪ Speaking engagements, where ever possible, to the target audience;
▪ Lunch and learn sessions with relevant professionals such as: energy managers, architects, engineering consultants, property developers.
Potential magazine and webpage advertisements with publications and organizations such as: AIBC / ArchitectureBC magazine, APEGBC / Innovation magazine, BOMA BC eNews, ASHRAE-BC Totem newsletter, Agriculture Climate Action Initiative funding catalogue, and BC Greenhouse Growers Association.</td></tr>
</table>

Evaluation Strategy	Simple deemed savings cannot be used due to the custom nature of the measures. The savings must be individually established for each and every participant. For new construction: the actual gas consumption will be compared to: a. Consumption prescribed per ASHRAE 90.1; and b. Qualified consultant's estimated consumption. For retrofits: Post retrofit, the actual gas consumption will be compared to: a. Weather normalized pre-retrofit gas consumption; and b. Qualified consultant's estimated consumption. Evaluation of the program savings and performance is assured by comparing pre construction data to post construction data. A thorough review could occur after approximately 30 participants have had their energy saving measures in place for at least one full year.

4.4.3.2.2 2010 Commercial Custom Design Program Results

The Companies have worked throughout 2010 on the development of the Commercial Custom Design program, in preparation for a phased roll out of the program in 2011. The Companies have completed the following items:

- Business case development and approval;
- Development of qualified consultant eligibility criteria and application;
- Development of joint Energy Study Guide for retrofit projects with program partner BC Hydro; and
- Development of Capital Cost Agreement, including approval letter, application form, and program general terms and conditions.
- Collaboration with School District No 23 (Central Okanagan) on a pilot study of a geo exchange heating system in a school setting.

The Companies have also worked with BC Hydro to develop the framework of a program specific partnership agreement that will allow the two utilities to operate the Commercial Custom Design program in tandem with BC Hydro's High Performance New Construction program and Power Smart Partners Retrofit program.

Significantly, the Companies have been using the proposed program's process flow and funding model within the PSECA initiative discussed above. As such the Companies have gained a great deal of experience working collaboratively with BC Hydro, as well as insight into the results that may be expected from the application of the funding model. Given that all energy saving measures must exceed the TRC hurdle to be eligible for funding, the Companies also expect a strong cost benefit ratio from the program, indicating cost effective energy saving measures are being incented.

4.4.3.2.3 2011 Commercial Custom Design Program Performance Forecast

Rolling out the Commercial Custom Design program will be a primary focus of the commercial programs team in 2011. Several items remain to be completed before the program can officially begin providing incentives. These include:

- Contribution agreement with BC Hydro to be finalized and signed;
- Program operations / process flow to be worked out with BC Hydro; and
- Energy Study agreement for natural gas only retrofit projects to be developed.

The Companies foresee adopting a phased roll out of the program. The new construction version of the program will be launched first and will begin providing incentives in collaboration with BC Hydro's High Performance New Construction program. Natural gas only projects for the retrofit market will be the next market segment served. Finally, retrofit projects touching on both electricity and natural gas will be provided with incentives. This will allow the utilities the opportunity to roll out the new construction program early in the new year while working through how to collaborate on retrofit projects. Meanwhile the Companies will be able to encourage retrofit projects that focus on natural gas reductions only. It should be noted that the Companies also intent to pursue a similar arrangement with FortisBC Inc. The program is complex, however, requiring a great deal of collaboration, well organized and detailed program processes, and ultimately dedicated administrative resources in order to ensure smooth operation. For this reason, the Companies are focusing on building the program with one partner at a time, beginning with BC Hydro.

4.4.3.2.4 Commercial Custom Design Program Summary

The Companies believe that, similar to the PSECA initiative, the new Commercial Custom Design program will encourage participants to implement energy saving measures that would not otherwise be installed without the incentive. The program will fill a role that is currently void within the Companies' commercial program offerings: providing incentives for non-prescriptive, custom designed and built measures to reduce natural gas consumption at the participant's facility. The program will leverage the reach of BC Hydro PowerSmart's current programs, to encourage the participation of more projects that the Companies could achieve by themselves. The Companies believe the proposed program will be a strong generator of value and successfully contribute to reduced natural gas consumption.

4.4.3.3 Continuous Optimization Program

4.4.3.3.1 Program Overview

Continuous Optimization Program	
Market	Retrofit
Duration	FEI: To be determined

	FEVI: To be determined
Incentive	Financial incentives based on implementation of commissioning measures
Partner	FortisBC Inc / BC Hydro
Overview	
Background	In most commercial buildings, operational problems such as duct leakage, unbalanced airflow, and poor scheduling are not always obvious and tend to be ignored or simply missed, resulting in inefficiencies and increased natural gas consumption. Building commissioning and real time energy consumption monitoring identifies otherwise virtually undetectable building faults/deficiencies that otherwise tend to go unnoticed by building designers, operators, and owners. In a continuous optimization program, problems are more easily detected, evaluated, and solved. Moreover, building commissioning represents one of the most cost effective sources of energy savings and GHG emissions reductions. Monitoring based commissioning ("MBCx") helps ensure the benefits of building commissioning are not lost over time by providing support for real time energy monitoring.
Description	The Continuous Optimization program will capture gas savings by ensuring participating facilities / buildings are operated in the most efficient and effective manner possible. Beyond reducing natural gas consumption, the program is also aimed at entrenching a culture of conservation. This will be accomplished by providing incentives for: 1. Commissioning: Utility funded commissioning studies and a concomitant obligation on the part of the participants to implement any measures identified therein with a two year payback or less. 2. Real-time monitoring: Utility funded installation of pulse meters and monitoring software for natural gas. Target participants will generally include government, medium to large commercial, large multi-residential, health care, education, and institutional organizations. The program will likely be delivered in the form of a performance based incentive, wherein participants will be given a certain dollar amount per GJ actually saved. The Companies are looking to partner with FortisBC Inc. on a new program and BC Hydro on its currently operating Continuous Optimization program.
Goals	• Reduce gas consumption among the commercial sector's existing building stock by providing an incentive to help commercial customers maximize their facilities operating performance. • Educate commercial sector customers about the impacts of poorly maintained / operated building systems and provide an incentive to facilitate both the maintenance of existing equipment, as well as the implementation of proper operating strategies. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs. • Increase year over year participation rates in view of maximizing gas savings.
Implementation	
Administration	Administration to be handled by the program partners: FortisBC Inc. and BC Hydro.
Communications	To be determined

Evaluation Strategy	Evaluation of the program savings and performance is inherent to the program. The digital Energy Management Information System will provide real time energy consumption monitoring allowing for extremely granular data collection and reporting. The information could be used as a baseline for other projects and as a leading example for other campuses and buildings around the province.

4.4.3.3.2 2010 Continuous Optimization Program Results

In 2010, the program was not yet launched, but extensive research was undertaken in order to lay the foundation for the program. Based on the available data from BC Hydro's current program, as well as the conclusions of various research papers, the potential natural gas savings are significant. The Companies' own work to assess the costs associated with the measure strongly suggests the cost benefit ratio for commercial facilities of sufficient size will be generally positive.

In order to further validate the Companies' conclusions and gain experience with this potentially large program the Companies have completed a business case and set up a pilot program in partnership with FortisBC Inc. to be launched in 2011. The Companies expect this program will lead to reduced natural gas consumption and assist in driving behaviour change by highlighting the performance and efficiency of a well operated facility. Increased awareness and emphasis on building operations will thereby be achieved.

4.4.3.3.3 2011 Continuous Optimization Program Performance Forecast

The Companies will launch a pilot version of the Continuous Optimization program in partnership with FortisBC Inc., as of March 28. This limited scale pilot will allow the Companies to become familiar with the details of a Continuous Optimization program and use the insight gained to develop a full scale program.

This pilot program will provide funding towards the implementation of a Continuous Optimization program at nine buildings on the UBC Okanagan campus. The pilot program's objectives are:

1. To save approximately 19,000 GJs over a three year period;
2. To gain expertise with the design, operation, and savings potential of a Continuous Optimization program; and
3. To further inter-utility cooperation on DSM initiatives by working with FortisBC Inc. with a view of eventually implementing a full scale Continuous Optimization program.

Also in 2011, the Companies will be working with BC Hydro to develop a business case for the remainder of FEI and FEVI's service territories. Providing the necessary tools to industry, the program will help bring about behaviour change, encouraging applicants to reduce natural gas consumption. BC Hydro has indicated the financial commitment is considerable.

Continuous Optimization Program Summary

The Companies believe the program will effectively encourage reduced natural gas consumption by providing building operators with greater insight into the ongoing, day-to-day operations of their facilities. The role of building commissioning will especially be highlighted while capacity and expertise will be developed within the industry in BC. Overall, the Companies believe a Continuous Optimization program has a genuine potential to raise the profile of building operations within discussions on energy efficiency and lead to improved building management practices, and thereby reduced natural gas consumption in the long term.

4.4.3.4 Commercial Kitchen Program

4.4.3.4.1 Program Overview

Commercial Kitchen Program	
Market	New Construction / Retrofit
Duration	FEI: To be determined FEVI: To be determined
Incentive	To be determined
Partner	To be determined
Overview	
Background	According to the preliminary results of the 2011 Commercial Sector Conservation Potential Review, commercial cooking represents the third greatest consumer of gas by volume. Cooking operations are estimated to consume 9.2% of total commercial natural gas consumption in the province. In fact, commercial food service establishments are the most intensive users of natural gas, on a per square foot basis, of all commercial sector market participants. The Companies are not aware of any current regulation establishing minimum required efficiency standards for commercial cooking appliances; however, higher efficiency options exist and their use is commonly encouraged by utilities in the United States.
Description	The Commercial Kitchen program will capture gas savings by encouraging the use of high efficiency (i.e. generally ENERGY STAR® rated or equivalent) cooking appliances in commercial kitchens. Typical appliances include fryers, ovens, boilers, steamers, and ranges. Target participants will include restaurants, health care facilities, care homes, education facilities, and institutional organizations. The program will likely be delivered in the form of an appliance purchase rebate.
Goals	• Reduce gas consumption in commercial cooking operations by encouraging the installation and use of high as opposed to standard efficiency cooking appliances. • Increase year over year participation rates in view of maximizing gas savings and bringing about market transformation. • Educate commercial kitchen customers about the advantages of reducing gas consumption and provide an incentive to facilitate the purchase of high efficiency technology. • Maintain a program TRC score greater than 1.0 and optimize the proportion

	of incentives over administration and marketing costs. • Prepare the way for and support any provincial regulation requiring increased commercial cooking appliance efficiency.
Implementation	
Administration	To be determined
Communications	To be determined
Evaluation Strategy	To be determined

4.4.3.4.2 2011 Commercial Kitchen Program Performance Forecast

The Companies are currently in the process of engaging an external consultant to develop an outline of a commercial cooking natural gas efficiency program for FortisBC.

As with the low flow pre rinse spray valve programs, the Companies believe the dynamics of the food service industry make it necessary to operate a DSM program in order to capture the potential natural gas savings offered by higher efficiency cooking equipment. The commercial food service sector tends to be exposed to significant volatility, making "cheapest first cost" a critical purchase decision criteria for any item not critical to customer service. Food service establishments typically lack the time or resources to research energy saving options or understand the benefits provided. A utility funded DSM program would make it easy for participants to save natural gas by largely eliminating both the effort and risk that potential participants would normally associate with the selection of high efficiency options.

The Commercial Kitchen program will also help to introduce a new concept to the food service industry, namely that energy is a variable cost. The Companies believe most food service establishments consider energy to be a fixed cost, and believe that changing this mindset is essential to ultimately bringing about market transformation.

The remaining development work preceding the program roll out is significant; however, the Companies' hope to launch the program towards the end of 2011. BC Hydro has recently launched a new program aimed at encouraging energy efficiency in commercial food service establishments. The Companies and BC Hydro have expressed interest in working together to promote greater energy efficiency among commercial food service establishments.

4.4.3.4.3 Commercial Kitchen Program Summary

The Companies believe commercial cooking operations represent a significant consumer of natural gas that is underserved by the current program offerings. Providing incentives to significantly reduce the incremental cost of higher efficiency cooking equipment is expected to encourage customers who would normally purchase and install standard efficiency equipment to purchase high efficiency options instead and reduce natural gas use as a result.

4.4.3.5 Process Heat Program

4.4.3.5.1 Program Overview

Process Heat Program	
Market	Retrofit
Duration	FEI: To be determined FEVI: To be determined
Incentive	To be determined
Partner	To be determined
Overview	
Background	Process loads can be defined as the consumption of natural gas for purposes other than space and/or domestic water heating for human comfort and sanitation. For process loads the consumption of natural gas is directly related to the production of some good or product of economic value. Process loads are a major driver of natural gas consumption among industrial customers, both large and small. According to the Companies' 2010 Conservation potential review industrial accounts consume over 39,846,000 GJ/yr of natural gas in 2010. Non-interruptible consumption in 2010 is approximately 11,466,000 GJ. This consumption is largely driven by process loads such as food and beverage processing, agricultural processes and wood product processing and drying. Currently the Companies do not offer any programs designed specifically to encourage capital upgrades or behaviour change to reduce natural gas consumption for light/small scale industrial processes. According to the process heat program development undertaken thus far, higher efficiency options do exist however; technologies such as high efficiency boilers, water heaters, ovens, steam boiler upgrades and direct fired equipment can be used to substantially reduce the natural gas consumption of manufacturing processes.
Description	The Process Heat program will capture gas savings by directly addressing inefficient equipment or operations in manufacturing processes. This may include items such as old boilers, piping insulation, process controls, and so on. Target participants will include organizations in agriculture, food processing, and manufacturing (i.e. asphalt production). The program is likely to include a capital cost incentive and may include an additional monitoring and performance incentive.
Goals	• Reduce gas consumption among manufacturing / light industrial customers by encouraging the installation and use of high as opposed to standard efficiency water appliances in manufacturing processes. • Increase year over year participation rates in view of maximizing gas savings. • Educate manufacturing / light industrial customers about the advantages of reducing gas consumption and provide an incentive to facilitate the purchase of high efficiency technology. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.

Implementation	
Administration	To be determined
Communications	To be determined
Evaluation Strategy	To be determined

4.4.3.5.2 2011 Process Heat Program Performance Forecast

The Companies have been working with a consultant to outline an incentive program designed to reduce the natural gas consumption of light industrial processes. It is expected that in 2011 work will be complete on the initial research and the Companies will be able to finalize a program design and launch the initiative in the second half of the year.

4.4.3.5.3 Process Heat Program Summary

Process heating in manufacturing and light industrial businesses represents a considerable consumption of natural gas that is not currently addressed by the Companies' existing incentive program. The Companies' experience with the Energy Assessment Program, however, suggests these customers represent a considerable energy savings potential. It is comparatively easy to encourage these customers to choose high efficiency options as they are predisposed to consider carefully the costs of all inputs to their business processes. The Companies expect that making incentives available to such customers will tip the balance of investment decisions in favour of high efficiency options by helping eliminate the risk of a higher capital investment in sometimes uncertain business climates.

4.4.3.6 Multi Unit Residential Building Program

4.4.3.6.1 Program Overview

Multi Unit Residential Building Program	
Market	New Construction / Retrofit
Duration	FEI: To be determined FEVI: To be determined
Incentive	To be determined
Partner	To be determined
Background	
Background	The 2005 Conservation Potential Review has indicated that MURBs represent one of the most significant sources for energy savings in the commercial sector. Although several of the current commercial programs can be applied to MURBs, there are several other smaller measures the Companies can implement for this sector that reflect rather large savings potentials.

Description	A suite of rebates targeted primarily at "in-suite" energy saving measures for MURBs. This may include measures such as low flow fixtures, fireplace programs, natural gas appliance upgrades, and/or building envelope upgrades. With large potential savings, this program will be targeting both new construction and retrofit applications.
Goals	• Educate builders and developers about installing energy efficient appliances and fixtures to drive market transformation. • Reduce natural gas consumption in the MURB sector by encouraging the installation and use of high efficiency options as opposed to standard efficiency models. • Maintain a program TRC score greater than 1.0 and optimize the proportion of incentives over administration and marketing costs.
Implementation	
Administration	To be determined
Communications	To be determined
Evaluation Strategy	To be determined

4.4.3.6.2 2011 Multi Unit Residential Building Program Performance Forecast

The Companies began their involvement in 2010 by participating in a MURB remediation study and reviewing energy consumption (among other items) in strata properties throughout the year. A cross functional team was established in early 2011 to start developing the MURB program. For resources, the commercial team is drawing on experience from the residential team, the sales team, and an energy specialist working in industry funded by the Companies. Initial talks are looking at the measures that show the most potential energy savings. The savings projections for low flow fixtures are very positive, as are fireplace programs and building envelope and domestic natural gas appliances upgrades.

The team is looking towards providing FortisBC Energy packaged options for MURBs for both new construction and retrofit applications – each targeting different groups. The 'package of measures' idea would work well in new construction when targeting developers. Working with the developer in the early stages and providing enticing financial incentives would ensure more MURBs were built from the ground up with energy efficient appliances and fixtures.

In retrofit applications, the program will primarily target apartment building owners and strata corporations. The program will look at several measures these target groups can take advantage of for upgrading to more energy efficient options in their buildings and will allow them to participate whether they are upgrading to low flow fixtures or replacing the decorative fireplaces with EnerChoice models. By allowing a broad range of options for the buildings, the program will hopefully increase participation levels and provide the target groups that represent buildings of different sizes, age, and 'green status' with the flexibility to choose what works for them.

4.4.3.6.3 *Multi Unit Residential Building Program Summary*

This program is targeted at overall behavioural change in the MURB sector. By providing substantial incentives to developers, there will start to be a shift in the industry that will help drive market transformation. As more MURBs undergo retrofits using energy efficient measures, there will not only be substantial energy savings, but also increased capacity and industry experience. With such a range of upgrade options and financial incentives, more target groups will choose to take advantage of these incentives than normally would if no such program was in place. The program development team is currently researching the measures and implementation options to best decide how to proceed to the next steps for a 2011 program launch.

4.4.4 ON FARM ENERGY ASSESSMENTS

Throughout 2010 and into 2011 the Companies have provided support to the On Farm Energy Assessment program managed by the BC Agriculture Research and Development Council ("ARDCorp"). The aim of participation in this initiative is to gain a clear understanding of how farms use natural gas, and what an appropriate incentive program may be for this customer segment. While the provincial utility companies do offer some energy efficiency support to agri-food operations, the Companies believe a specialized approach is ultimately required for agriculture because of the sector's specific production systems and technologies.

Project Objectives

- To determine the sector's key energy efficiency needs and to identify gaps in current programming and incentives.
- To determine the potential for cost savings and GHG emissions reductions through on farm energy efficiency assessments in BC.
- To identify opportunities associated with recovery/recycling of wasted energy and/or on farm energy production.

Upon completion of the initiative the Companies will be provided with the findings in a report format. These findings will be used to develop incentive programs designed for the specific needs of the agriculture sector. The preliminary findings suggest that significant savings potential exists among greenhouse operations first and foremost and poultry operations next. Field crops represent limited savings potential for natural gas.

4.5 Summary

Energy efficiency in the commercial sector represents a considerable opportunity to achieve natural gas savings and GHG emissions reductions. With more options available for investment and fewer minimum equipment efficiency standards than in the residential sector, at least in the short to medium term, sizeable cost effective investments can be made to help commercial sector customers reduce their energy consumption, as demonstrated by the PSECA initiative.

The challenge to achieving these savings is having the right programs, designed to suit the myriad of commercial sector needs, in place and effectively delivered to potential participants.

The commercial energy efficiency and conservation programs have delivered value and will continue to do so by effectively encouraging commercial customers to implement measures that reduce their natural gas consumption. Encouraging reduced consumption today paves the way for market transformation and the achievement of the government's energy and climate change objectives over the long run.

5 HIGH CARBON FUEL SWITCHING PROGRAMS

5.1 Overview

The High Carbon Fuel Switching program area initiatives are designed to result in lower overall GHG emissions by using natural gas in place of higher emissions carbon fuels such as coal, oil, diesel, or propane. In addition, further GJ savings are recovered by replacing older, less efficient high-carbon appliances with high efficiency natural gas technologies. The first fuel switching program is the residential retrofit program, focused on converting oil or propane heating systems to ENERGY STAR® natural gas appliances. This program, called the Switch N' Shrink program, saves money and energy and results in significant GHG emissions reductions.

In Order No. G-36-09, the Companies received approval for residential fuel switching program funding for fuel switching from fossil fuels with higher carbon content than that of natural gas. In the residential sector, this applies to the installation of ENERGY STAR® and EnerChoice equipment for customers choosing to convert to natural gas. FEVI received approval for the extension of 2010 high carbon fuel conversion funding amounting to $1.5 million for 2011 in Order No. G-140-09, as part of the 2010-2011 Revenue Requirements Application's Negotiated Settlement Agreement. This funding is in place to develop EEC programs that benefit customers transitioning from higher carbon fuels such as coal, oil, diesel, or propane to natural gas.

This principle of moving customers from higher carbon fuel to natural gas also applies in other sectors, including the transportation sector. As described in the Innovative Technologies program area, heavy duty vehicles fuelled by lower carbon Compressed Natural Gas ("CNG") can displace higher carbon diesel to achieve significant environmental benefits. The Companies' target market includes operators of commercial, return-to-base heavy duty fleet vehicles such as garbage trucks, waste haulers, and buses. Improvements in engine technology, combined with an attractive price differential between natural gas and diesel have stimulated renewed interest in CNG NGVs in recent years.

5.1.1 RESIDENTIAL HIGH CARBON FUEL SWITCHING PROGRAM GOALS

Residential fuel switching programs encourage households to replace their higher carbon heating systems with lower carbon natural gas. These programs add value to new and existing customers through reduced fuel costs, minimizing the environmental hazards associated with oil storage tanks, decreasing the need to import fuel from other provinces, and improved air quality in the home. Residential fuel switching programs support the following objectives:

- Educate customers about the advantages of replacing higher carbon heating systems with lower carbon natural gas in terms of lower fuel cost, GHG emissions reductions, and other benefits;
- Upgrade low efficiency systems to high efficiency systems in order to capture energy savings associated with reducing the overall consumption of fuel; and

- Support government policy on energy efficiency and GHG emissions reductions, especially in relation to efficient building strategies[31] through incentives and education to customers and other industry stakeholders.

5.2 2010 Residential High Carbon Fuel Switching Program Area Results

The 2010 High Carbon Fuel Switching program, Switch N' Shrink, resulted in the replacement of 178 heating systems through a cost effective program with a TRC score over 1.2, as outlined in Table 5-1. Further analysis based on the amount of oil displaced reveals that customers reduced their fuel costs by $596,000[32] over the lifetime of the measure, thereby reducing over 1,170 tons of GHG emissions. Please note natural gas savings are negative for this program since the addition of these customers is building load.

Table 5-1: High Carbon Fuel Switching 2010 Results

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Swtich 'N' Shrink	75	225	299	(6,103)	(32,529)	(38,632)	1.2	1.4

In addition to appliance replacement, this program met EEC program objectives by educating customers and trades about the benefits of replacing higher carbon heating systems with energy efficient appliances. These benefits include the reduction of ongoing fuel costs, improved air quality, and decreased environmental risk associated with oil tanks and fuel transport. The primary program benefit was supporting government policy initiatives to reduce GHG emissions.

5.3 2011 Residential High Carbon Fuel Switching Program Area Outlook

The 2011 outlook for the High Carbon Fuel Switching program area at this time consists only of the residential Switch N' Shrink program although. The Companies are assessing other opportunities for this program area in the coming months. By building on 2010 program awareness, program participation is expected to more than double for a total of 420 participants as outlined in Table 5-2 for the 2011 forecast. The 2011 program cost effectiveness is higher than 2010 due to decreased marketing expenditures required in the second year and the higher avoided cost of oil that is forecasted to increase from $22 per GJ in 2010 economic models, to $25 per GJ in 2011 based on Vancouver, BC pricing.[33]

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[31] BC Energy Efficient Buildings Strategy: More Action, Less Energy. BC Ministry of Energy and Mines Publication, 2008.

[32] www.kentmarketingservices.com Prepared by MJ Ervin, Kent Marketing Services, for source of Vancouver fuel oil prices. For economic modeling, 2010 cost of oil was assumed to be $22.01 and 2011 cost of oil was assumed to be $25.39.

[33] ibid

Table 5-2: High Carbon Fuel Switching 2011 Outlook

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Swtich 'N' Shrink	121	403	524	(17,116)	(69,861)	(86,976)	1.7	1.8

5.4 Residential High Carbon Fuel Switching Program Details

5.4.1 ACTIVE PROGRAMS

5.4.1.1 Switch N' Shrink Program

5.4.1.1.1 Program Overview

Switch N' Shrink Program	
Target Audience	Residential retrofit households with oil or propane as primary fuel source FEVI is the primary market where oil heating is prevalent
Duration	Jan 1, 2010 - Dec 31, 2011
Incentive	$1,000 for upgrading an oil/propane primary heating system to an ENERGY STAR® natural gas primary heating system. An additional $50 for Electronically Commutated Motors ("ECM") incentive is funded by BC Hydro and FortisBC Inc
Partners	BCHydro and FortisBC Inc. for ECM motors
Overview	
Background	The Switch N' Shrink program is offered to all BC residents; however, the primary focus will be on Vancouver Island where the use of oil is more prevalent than in the rest of the Companies' service territories. Furthermore, the program will engage residents near a gas main who are more likely to participate and take advantage of this program. On-Main market potential for FEVI oil and propane conversions is difficult to estimate, but could range from 20,000 to 40,000 households. According to 2005 data from Statistics Canada, 21% of households within the Victoria market still used oil as their primary heating fuel while only 19% used natural gas[34]. This market potential demonstrates a significant opportunity to reduce GHG emissions through natural gas conversions for Vancouver Island communities. There are also opportunities for conversion projects in the Interior, as well as the opportunity for customers in regions such as Revelstoke, which are serviced by propane, to switch from higher carbon oil to propane. In addition to the benefit of GHG emissions reductions, participants will lower

[34] 2005 Statistics Canada - Table 203-0019 - Survey of household spending (SHS), dwelling characteristics at the time of interview by province, territory, and selected metropolitan areas, annual (1,2,3,9,11). Survey or program details: Victoria, British Columbia [59935], Survey of Household Spending – 3508.

	their energy bills, increase their property values, and reduce the potential of an environmental hazard associated with oil tank leaks.
Description	The Switch N' Shrink program offers a $1,000 incentive to new or existing customers who upgrade their primary home heating system (furnace or boiler) from oil/propane to a high efficiency ENERGY STAR® natural gas heating system. An additional $50 rebate, funded by BC Hydro and FortisBC Inc., will be provided to those participants who purchase a model with an ECM motor.
Goals	• Provide a $1,000 incentive to encourage homeowners to convert their primary heating system from higher carbon oil or propane to a high efficiency natural gas heating system. • Work with the Ministry of Energy to include this program as part of the provincial GHG emissions reduction strategy. • Develop a cost effective program with a TRC score greater than 1.0 that achieves significant energy savings, cost savings, and GHG emissions reduction benefits.
Implementation	
Administration	Consumer Response Marketing Ltd.
Communications	The Companies adopted an integrated marketing approach with print ads and radio to drive program awareness, contractor communications, co-marketing with furnace manufacturers, and educating internal stakeholders such as the customer service installation centre and sales and service staff who can help promote higher carbon to lower carbon conversions.
Evaluation Strategy	The Companies will be conducting a survey with participating contractors to determine how to drive program participation and other ideas to improve the program.

5.4.1.1.2 2010 Results

Table 5-3: 2010 Switch N' Shrink Program Results

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)*	NPV Energy Savings (GJ)*	Free Rider Rate	TRC
	FEI	29	29	46	(624)	(6,103)	50%	1.2
	FEVI	149	149	76	(3,204)	(32,529)	50%	1.4
	Total	178	178	121	(3,827)	(38,632)	50%	1.5

* Note: Energy savings in a fuel switching program are negative since this is a load building program from higher carbon fuel sources (oil and propane) to lower carbon natural gas.

The Switch N' Shrink program provided EEC funding for 178 conversions from oil to natural gas. Table 5-4 demonstrates the program is cost effective with a TRC score of 1.4. Approximately $100,000 was invested in print and radio advertising in the fall of 2010 to drive program awareness and educate homeowners about the benefits of replacing higher carbon fuels with lower carbon fuels.

Table 5-4: 2010 Switch N' Shrink Program Benefits

Utility	NPV Natural Gas Incurred (GJ)	NPV Oil Displaced (GJ)	NPV Energy Savings (GJ)	NPV Costs to Purchase Natural Gas ($000s)	NPV Costs to Purchase Oil ($000s)	NPV Cost Savings upon Conversion ($000s)	GHG Savings (Ton CO2 equivalents)
FEI	6,103	7,222	1,119	61	159	98	200
FEVI	32,529	37,106	4,577	337	835	498	971
Total	**38,632**	**44,328**	**5,696**	**398**	**994**	**596**	**1,171**

Table 5-5 provides insight into the considerable program benefits over the lifetime of the measure. For 178 conversions, there were 5,696 net GJs of energy saved, $596,000[35] in net cost savings for these customers, and 1,171 net tons of CO2e reductions.

5.4.1.1.3 2011 Performance Outlook

Table 5-5: 2011 Switch N' Shrink Program Performance Forecast

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)*	NPV Energy Savings (GJ)*	Free Rider Rate	TRC
FEI	100	100	21	(1,720)	(17,116)	50%	1.7
FEVI	320	320	83	(6,880)	(69,861)	50%	1.8
Total	420	420	104	(8,600)	(86,976)	50%	1.8

* Note: Energy savings in a fuel switching program are negative since this is a load building program from higher carbon fuel sources (oil and propane) to lower carbon natural gas.

The Switch N' Shrink program will remain in market for 2011 and 2012 subject to BCUC funding approval for fuel switching activities. By leveraging program awareness from the fall 2010

35 www.kentmarketingservices.com Prepared by MJ Ervin, Kent Marketing Services, for source of Vancouver fuel oil prices. For economic modeling, 2010 cost of oil was assumed to be $22.01 and 2011 cost of oil was assumed to be $25.39.

advertising campaign, the Companies anticipate doubling participation from 178 to 420 participants. A fall 2011 advertising campaign is under consideration, with a decision to be made based on contractor feedback and program participation trends.

Table 5-6: 2011 Switch N' Shrink Forecasted Program Benefits

Utility	NPV Natural Gas Incurred (GJ)	NPV Oil Displaced (GJ)	NPV Energy Savings (GJ)	NPV Costs to Purchase Natural Gas ($000s)	NPV Costs to Purchase Oil ($000s)	NPV Cost Savings upon Conversion ($000s)	GHG Savings (Ton CO2 equivalents)
FEI	17,116	19,923	2,807	178	506	328	539
FEVI	69,861	79,691	9,831	741	2,023	1,283	2,085
Total	**86,976**	**99,614**	**12,637**	**918**	**2,529**	**1,611**	**2,624**

Table 5-6 provides insight into the considerable program benefits over the lifetime of the measure. For the forecasted 420 conversions, there are 12,637 net GJs of energy saved, $1,611,000[36] in net cost savings for these customers, and 2,624 net tons of CO2e reductions.

5.5 Summary

The overall program benefits are captured by avoiding higher carbon fuel costs while incurring lower natural gas fuel costs for an overall reduction in net GHG emissions. The net benefit for the participant is in reduced energy costs while helping BC meet its provincial GHG emissions reduction targets. From a utility standpoint, the benefit is in adding more customers to the distribution system, especially where a gas service already exists in close proximity, keeping the overall system costs per customer down. The 2011 performance outlook illustrates these points and the significant energy, cost, and GHG emissions savings that are obtained based on 420 heating systems converted from oil to natural gas.

The Companies will be assessing other opportunities to utilize this funding for high carbon to lower carbon initiatives. As the price of oil appears to be rising, there will be even greater cost benefits to customers to define programs for this program area.

[36] Ibid.

6 CONSERVATION FOR AFFORDABLE HOUSING PROGRAMS

6.1 Overview

The Conservation for Affordable Housing program area is the Companies' area of DSM programming specifically created to meet the needs of our low income customers. One of the EEC program principles is that "programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative" (Energy Efficiency and Conservation Programs Application, May 28, 2008, pg 47). The Companies are staying true to this principle by developing and implementing programs that are of no cost or low cost to low income participants. Further, as per the Demand-Side Measures Regulation, a utilities' DSM portfolio is considered adequate (by the authorities) when there is "a demand-side measure intended specifically to assist residents of low income households to reduce their energy consumption" (November 7, 2008, Regulation of the Minister of Energy, Mines and Petroleum Resources, Ministerial Order No. M 271, Section 3[a]). In order to recognize its importance, the Companies created a discrete program area for Conservation for Affordable Housing in 2009, which focuses on assisting our low income customers to reduce their energy consumption, which in turn reduces their energy costs.

In line with the Commission's encouragement to "re-allocate funding from other approved areas" (EEC Decision, Order No. G-36-09), the Companies requested and were approved for an annual total budget of $3 million for 2010 and 2011, encompassing both FEI and FEVI in this program area (as part of Orders G-141-09 and G-140-09 approving negotiated settlement agreements in FEI's and FEVI's 2010 - 2011 Revenue Requirements Applications). With energy rates generally increasing, it will remain important for the Companies to create energy conservation opportunities for this segment in a manner that allows customers to participate without having to spend a significant amount of their limited income.

Low income customers are known to be difficult to reach and be integrated into utilities' DSM programs; therefore, this program area is especially well suited to working collaboratively with FortisBC Inc. and BC Hydro in order to simplify the application processes for the customer and share administration and outreach activities and costs. This streamlined approach allows the Companies to maximize every contact to ensure that once a low-income customer is engaged, an optimal amount of energy savings can be realized.

It should be noted that providing conservation and energy efficiency programs for low income customers can be challenged in terms of achieving a positive TRC score, both at the program area and individual program levels, despite the 30 percent benefits adder provided for in the DSM regulation. This is because of the relatively high cost of providing conservation services to this important customer segment. Recognizing that the provision of conservation services to low income customers is a requirement for adequacy of utility DSM activity, the Companies intend to work with government to explore amending the DSM regulation to ensure conservation activity serving this customer segment is able to continue.

6.2 2010 Conservation for Affordable Housing Program Area Results

While 2009 laid some good foundations in research, facilitation, and planning, 2010 saw the launch of two significant Conservation for Affordable Housing programs, the completion of an insightful study, and investments made under the Ministry of Energy and Mines Low Income Partnership grant. We also laid further groundwork on a much expanded program offering for 2011.

Despite the added time required to effectively collaborate with partnering utilities, the Companies successfully launched two Conservation for Affordable Housing programs in 2010: the Residential Energy and Efficiency Works ("REnEW") program and the Energy Saving Kit ("ESK") program. The REnEW program is an innovative approach to energy efficiency trades training that simultaneously provides support to individuals facing barriers to employment. The ESK program provides a bundle of easy-to-install energy saving measures to low income customers.

In 2010, the Companies also saw the completion of the Strategic Energy Management Plan, a study that provided insight into the energy performance of over 900 buildings in the non-profit housing sector. Amongst many insightful findings, the study highlighted the importance of educational and engagement programs in the non-profit housing sector, as well as the need for dedicated energy professionals working in non-profit housing organizations.

The Companies continue to work collaboratively and in partnership with the Ministry of Energy and Mines on programs and projects focused on low income customers. This partnership involves a $5.155 million grant that was awarded to the Companies in March 2009. The work completed in 2010 under this grant was specific to a new initiative, the Super Efficient New Construction ("SENC") project, which seeks to incent both new construction that is far more efficient than current building code requirements and new housing units for low-income tenants. It's important to note that activities associated with the Low Income Partnership grant are described within this report; however, they are incremental to the EEC portfolio and thus are not included in the EEC portfolio TRC calculations, or the Conservation for Affordable Housing program area TRC calculations.

Further, the Companies have laid the groundwork for greatly expanded programming in the low income sector for 2011. The Companies have made good progress in a partnership with BC Hydro on the Energy Conservation Assistance ("ECAP") program, which will be the first program to provide deep energy savings for low income gas customers through the direct installation of measures such as furnaces, draft-proofing, and insulation. Work also continued on a study that focuses on the opportunities within the complex co-operative housing sector of BC and a study that explores energy efficiency opportunities within the mobile home sector.

As demonstrated in the table below, the Companies have invested a total of $324,000 in 2010 and achieved a program area TRC score of 0.7 in FEI and 1.6 in FEVI. The main reason for the variance between FEI and FEVI is that the Companies have not implemented a REnEW session in the FEVI territory. In 2011, the intent is to expand the REnEW program into the FEVI territory. The Companies endeavoured to deliver the REnEW program in the FEVI territory in 2010;

however, the delivery partner on Vancouver Island experienced some organizational restructuring that conflicted with their ability to deliver the program. The delivery partner will be offered the opportunity to deliver the REnEW program in 2011.

The TRC score of 0.7 in FEI is due to the REnEW program's influence on the TRC. The REnEW program is a good example of a program that is hindered by conventional approaches to DSM program evaluation as there are no direct energy savings attributable to the program. In this sense, it can be considered an enabling activity. Further, because the REnEW program ran for a full year, while the ESK program (which had a very favourable TRC) was only available for the second half of the year, the REnEW program had a disproportional impact on the TRC. In other words, had both the REnEW program and the ESK program been available for the entire year, the portfolio TRC would have been improved.

Table 6-1: 2010 Conservation for Affordable Housing Investments

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Strategic Energy Management Plan (Study)	$14	$3	$17	N/A	N/A	N/A	N/A	N/A
REnEW	$148	N/A	$148	N/A	N/A	N/A	N/A	N/A
Energy Savings Kit	$83	$21	$104	15,520	3,959	19,479	2.3	2.4
Mobile Homes (Study)	$8	$2	$10	N/A	N/A	N/A	N/A	N/A
Non-Program Specific Expenditures	$43	$2	$45	N/A	N/A	N/A	N/A	N/A
Total	$296	$28	$324	15,520	3,959	19,479	0.7	1.6

Notable achievements through in 2010 in the Conservation for Affordable Housing program area are:

- The completion of the Strategic Energy Management Plan, a study focusing on the opportunities and best approaches for achieving energy efficiency and conservation within the non-profit housing sector;
- Investment of $148,000 in the REnEW program, which brought about the development of a robust course curriculum, strong partnerships with social agencies that serve various sub-segments of the low income sector, 59 REnEW participants, and participant satisfaction scores of 85%;
- Investment of $104,000 in the ESK program resulting from over 5,000 participants in the first six months of the program. The resultant savings from the ESK program is 19,479 GJs (NPV) and we are well positioned to reach an even greater breadth of the market in 2011; and
- Of the $5.155 million the Ministry of Energy and Mines granted to the Companies through the Low Income Partnership Grant, $515,000 was invested in SENC in 2010 and the Companies are well positioned to invest $1.5 million in collaboration with BC Hydro on the ECAP program in 2011. Note that this investment is not shown in the table above because the Ministry of Energy and Mines Low Income Partnership grant is incremental to the EEC funds.

- Overall, including both EEC funds shown in the table above, and the Ministry of Energy and Mines Low Income Partnership grant, the Companies have been successful in investing $839,000 in 2010.

6.3 2011 Conservation for Affordable Housing Program Area Outlook

Considerably expanded investment in the Conservation for Affordable Housing program area is expected in 2011. The most significant enhancement will be the launch of the partnership with BC Hydro on the ECAP. This program will see investments from both EEC funds and from the Ministry of Energy and Mines Low Income Partnership grant. The Companies will continue with their commitment to build expertise in this program area through additional research specifically in the co-operative housing sector and the mobile housing sector. The REnEW program and the ESK program will also continue throughout 2011. Table 6-2 provides an estimate of 2011 investment in the Conservation for Affordable Housing program area.

Table 6-2: 2011 Conservation for Affordable Housing Investment Forecast

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
REnEW	$150	$35	$185	N/A	N/A	N/A	N/A	N/A
Energy Savings Kit	$186	$47	$233	31,271	7,903	39,174	2.2	2.3
Energy Conservation Assistance Program	$1,694	$424	$2,118	53,242	13,089	66,331	0.6	0.6
Mobile Homes (Study)	$8	$2	$10	N/A	N/A	N/A	N/A	N/A
CHF Co-ops (Study)	$12	$3	$15	N/A	N/A	N/A	N/A	N/A
Non-Program Specific Expenditures	$7	$3	$10	N/A	N/A	N/A	N/A	N/A
Total	$2,058	$513	$2,571	84,514	20,992	105,505	0.7	0.7

Note that wherever a TRC result is presented in the Conservation for Affordable Housing program area, it includes a deemed benefit that includes a 30 percent "adder" in accordance with clause 4.2.b of the Demand Side Measures Regulation, attached as Appendix C. It should also be noted that there is a challenge in meeting a TRC score of 1.0 (even after applying the low income adder) for programs that seek to achieve a deeper level of savings (i.e. ECAP program) for the following reasons:

- Direct install low income programs will incur higher costs for administration and implementation. The Companies will need to hire skilled contractors and ensure they are trained in the sensitivities of working in low income households. They will also need to ensure these contractors are very familiar with the utilities' safety requirements and are trained to assess potential problem situations such as mould; and
- It is difficult to reach and integrate low income customers in programs that involve some effort on behalf of the customer to provide sufficient documentation of their household income. To overcome these barriers additional investments are required to support the customer through the application process.

To address these challenges, the Companies are working with government to explore alternatives to evaluating low income programs that better recognize the higher costs required to perform this type of work, as well as recognize the extensive benefits in performing this work that extend well beyond energy efficiency.

6.4 Conservation for Affordable Housing Program Details

As the Companies progress and enhance their program offerings and partnerships, the Companies continue to meet the regulatory requirement of designing programs that specifically "assist low income households to reduce their energy consumption." (November 7, 2008, Regulation of the Minister of Energy, Mines and Petroleum Resources, Ministerial Order No. M 271, Section 3[a]). We will continue to also stay true to our EEC program principle of "offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers." (Energy Efficiency and Conservation Programs Application, May 28, 2008, pg 47).

The Companies have made good progress in 2010 with the successful launch of two solid EEC programs geared specifically to low income customers. These programs will both continue in 2011. Through studies performed in 2010, relationships that have been built with non-profit housing providers, and collaborations with other BC utilities, 2011 is set to be a year of much expanded investment in the Conservation for Affordable Housing program area.

Conservation for Affordable Housing programs are outlined in Table 6-3 and described in further detail below.

Table 6-3: Conservation for Affordable Housing Initiatives for TGI and TGVI

Program	Utility		Description	TRC	
	FEI	FEVI		FEI	FEVI
Completed Programs					
Strategic Energy Management Plan	X	X	A study that provided insight into the energy performance of over 700 non-profit housing buildings.	N/A	N/A
Active Programs					
REnEW (Training program)	X		Energy efficiency trades training targeted to individuals that are facing barriers to employment.	N/A	N/A
Energy Savings Kit	X	X	A bundle of easy to install energy saving measures available to all low income customers.	2.3	2.4
Ministry of Energy Low Income Partnership Grant	X	X	Incentives invested in a number of initiatives including the Super Efficient New Construction project.	N/A	N/A
Programs in Development					
Energy Conservation Assistance Program	X	X	Energy audits and installed measures that will lead to deep energy savings for low-income customers.	0.6	0.6
CHF BC Energy Performance Housing Inventory	X	X	A study that will provide insight into the energy performance of the co-operative housing sector in BC.	N/A	N/A
Mobile Homes Study	X	X	A study focused on a survey of mobile home tenants, their attitudes towards energy efficiency, and opportunities that may be available within this housing type.	N/A	N/A

6.4.1 COMPLETED PROGRAMS

6.4.1.1 Strategic Energy Management Plan ("SEMP") Study

6.4.1.1.1 SEMP Study Overview

SEMP (Study)	
Target Audience	Non-profit Housing Sector in BC
Duration	Completed in October 2010
Financial Contribution	$16,984 of the Companies' contribution

Partners	The Strategic Energy Management Plan ("SEMP") was commissioned by the Companies and BC Hydro.
Overview	
Research Goals	This study was specifically focused on the non-profit housing sector and involved an analysis of energy data (consumption and behavioural habits) to create the benchmarking of building energy performance. A related goal of the study was to use the information to start to prioritize energy efficiency upgrades based on cost effectiveness, energy savings, and GHG emissions reduction potential.
Implementation	
Administration	The study was administered jointly by City Green Solutions and the BC Non-Profit Housing Association.
Key Findings	**Key Finding:** The average energy intensity of buildings where the society pays the utility charges was more than double the intensity of buildings where the tenants pay the utility charges; and, every one percent of energy reduction in the non-profit housing sector would result in $500,000 in energy savings annually. Study recommendations: • Prioritize energy efficiency retrofits in buildings where societies pay the utility charges; • Implement educational programs in buildings where societies pay the utility charges to bridge the gap between tenant behaviour and the cost to societies; and • Where feasible, explore sub-metering structures that draw a better correlation between tenant behaviour and the resultant benefits to the tenant. **Key Finding:** Non-profit buildings in the Lower Mainland are both the largest consumers of energy and the most energy intensive. Study recommendation: • Prioritize energy efficiency programming in the Lower Mainland. **Key Finding:** The range and depth of responsibilities required to manage energy use in non-profit housing is extensive. From the initial budgeting of capital costs and organizing energy assessments, to project oversight of building retrofits and tracking and monitoring energy performance, the capacity required for housing providers is beyond the existing organizational resources of most societies. Study recommendation: • A key recommendation to managing the responsibilities of energy efficiency within the non-profit sector is to add an energy manager(s) designated to the sector. The energy manager would provide the necessary link between government and utility programs and services and the buildings that could benefit from these services.

Actions	In alignment with the study recommendations, the Companies have undertaken the following initiatives: • In 2010, the Companies funded an energy specialist at BC Housing who will work closely with the Companies to spearhead energy efficiency programming in the sector. The Companies will encourage the prioritization of buildings that have the highest energy intensity; and • In 2011, the Companies will be collaborating with BC Housing on a tenant engagement pilot program that will educate on, and encourage, energy efficiency behaviours. The intention is to develop a successful engagement program that can be rolled out on a larger scale and on a more permanent basis.

6.4.2 ACTIVE PROGRAMS

6.4.2.1 Residential Energy and Efficiency Works Program ("REnEW")

6.4.2.1.1 REnEW Program Overview

Residential Energy and Efficiency Works Program ("REnEW")	
Target Audience	Participants trying to overcome barriers to employment and poverty who also have a desire to work in the energy efficiency retrofitting industry
Duration	Jan 1, 2010 - Dec 31, 2011
Incentive	Energy efficiency trade training at no cost to participant including course materials, first aid, Workplace Hazardous Materials Information System ("WHMIS") and other trade industry certifications, a set of tools and a tool belt, and two nutritious meals per day during training
Partners	BC Hydro, FortisBC Inc.
Overview	
Background	In recognition that BC has a shortage of skilled tradespeople that are well versed in energy efficiency, this program was launched with the objective of building capacity within the industry while simultaneously providing opportunities for a segment of our society that faces barriers to employment. This FortisBC Energy Inc. led training program provides an overview of the energy efficiency industry and its many associated trades. The training includes both entry-level trade skills, with respect to the installation of energy efficiency measures (i.e. showerheads, faucet aerators, and pipe insulation), and an introduction to more technical trade skills (i.e. installing energy efficient windows and insulation). This training program is targeted to participants with barriers to employment and has been designed with the following parameters: **Accessibility** – minimal experience/educational prerequisites. **Efficiency** – minimize the number of weeks of training (class and practical)

	needed to gain the required skills. **Quality** – provide sufficient training and experience so graduates can confidently install energy efficiency devices and educate others on behaviours that encourage energy conservation. The Companies, in collaboration with funding partners and delivery agents, has created a student manual and instructor manual for the REnEW program and is actively involved in helping the delivery agents find industry professionals to train the participants. In all four REnEW training sessions held in 2010, the energy efficiency component of the training was rounded out with training that the delivery agents recommended. This additional training typically included topics such as job readiness (i.e. expectations in the workplace), life skills training (i.e. healthy eating, budgeting, and so on), and third party trade certifications (i.e. first aid, WHMIS, fall protection, working in confined spaces, and the Construction Safety Training System). When a participant graduates from the program they are equipped with energy efficiency retrofit skills, industry certifications, renewed self-confidence, and a full set of tools. Graduates are job-ready.
Description	This training program is a full-time course that typically takes four to five weeks to complete. Half of the time is spent in the classroom and half is spent learning and practicing trade skills with a team of energy efficiency trade experts.
Goals	• Increase market capacity in the energy efficiency retrofit industry. • Increase the quality of energy efficiency retrofitting installations. • By increasing the supply of skilled energy efficiency tradespeople, the cost of having these retrofits implemented will ultimately decrease for both customers and utilities.
Implementation	
Administration	In 2010, the Companies worked with three non-profit delivery agents including: • John Howard Society of the Central and South Okanogan; • A.C.C.E.S.S. (Aboriginal Community Career Employment Services Society); and • Sto:Lo Nation. Each of these delivery agents were able to leverage their networks and relationships to create greater sharing of financial costs. Some of the additional funding that came through the delivery agents included contributions from BladeRunners, Service Canada, Province of British Columbia, Community Living, and the Ministry of Advanced Education and Labour Market Development.
Communications	The REnEW program is a highly targeted program, so very little marketing of the program has been necessary other than direct contact with delivery agents by the Conservation for Affordable Housing program manager. The Companies created posters that delivery agents use to inform and recruit participants to the program.

Evaluation	The REnEW program's success is predicated on providing a high quality and engaging training experience to participants in communities across BC. To measure this, participants are surveyed to gauge the Companies' success in providing a positive training experience; and, their satisfaction with the program is our indicator of how positive the training experience was. For the goal of increasing energy efficiency expertise in the trade industry, employment after graduating from the program is used as a gauge to measure direct impact on the industry. To this end, employment within two months of graduating from the REnEW program is tracked through our delivery agents.

6.4.2.1.2 2010 REnEW Program Results

In 2010, the Companies saw the launch of this innovative approach to creating capacity in the energy efficiency trade industry. Table 6-4 below shows the Companies invested $148,000 in the REnEW program in 2010. This investment was spread across the four REnEW sessions and the three delivery agents mentioned above, and resulted in 59 participants in the program.

Table 6-4: 2010 Program Actuals

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	59	N/A	$148	N/A	N/A	N/A	N/A
FEVI	0	N/A	$0	N/A	N/A	N/A	N/A

During the first implementation of this program, the Companies learned that smaller size classes are crucial to meeting the needs of the clientele who participate in this training program. Consequently, even though there were 59 participants within the four sessions we implemented in 2010, in 2011 we will set the maximum class size to 12 participants per session. By working with a very proficient group of non-profit delivery agents, using highly skilled trainers, and creating an engaging training experience, 95 percent of registered participants completed the course. At the end of every session, the participants completed a satisfaction survey and were asked to rate their satisfaction on a scale of one to five, with one representing poor satisfaction and five representing excellent satisfaction, and the average score for all four sessions was 4.2 or 85 percent.

In terms of direct impact on the energy efficiency trade, the Companies also tracked how many of the graduates were employed within two months of graduating from the program. The last two sessions were completed in December; therefore, at the time of writing this report, final results of employment from the last two sessions has not yet been determined. From the first two sessions, an average of 38 percent of participants were employed within two months of completing the program. Given that many of the participants were disconnected from the workforce entirely before completing this program, this is a very respectable result. Another favourable result is that the REnEW program had such a positive effect on participants' confidence that an average of 12 percent from the first two sessions went on to further their education. For example, one graduate went on to enrol in a GateWay to the Trades for Women course at Okanagan College. REnEW program results are summarized below in Table 6-5.

Table 6-5: 2010 REnEW Program Success Indicators

Indicator	2010 Performance
Participants in the program	59
Course completion rate	95%
Number of participants employed or furthering their education within two months of graduating	50%
Satisfaction of participants	85%

From the very early stages of program design, the Companies have worked collaboratively with other utilities and non-profit social agencies, and this approach has led to very efficient use of our investment in this program. The four sessions that were implemented in 2010 had a total cost of $489,031. By leveraging our relationships with FortisBC Inc. and BC Hydro, and leveraging funding that many non-profit organizations have in place, the Companies have invested $147,691 (30 percent of total costs). See Table 6-6 for REnEW cost sharing.

Table 6-6: 2010 REnEW Program Cost Sharing

Administrator	Total
Number of Participants	59
Total Cost of Program	$ 489,031
Contributions from Delivery Agents	$ 129,120
Contributions from Other Utilities	$ 212,219
Contribution from the Companies	$ 147,691

6.4.2.1.3 2011 REnEW Program Performance Forecast

Table 6-7: REnEW Program Performance Forecast for 2011

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	44	N/A	$150	N/A	N/A	N/A	N/A
FEVI	11	N/A	$35	N/A	N/A	N/A	N/A
Total	55	N/A	$185	N/A	N/A	N/A	N/A

In 2010, the Companies implemented four sessions of the REnEW program throughout communities in the FEI territory. In 2011, the intention is to implement an additional four sessions of the REnEW program in FEI's territory and extend the reach to the FEVI service territory as well. As additional programs are rolled out in 2011 under the Conservation for Affordable Housing program area, the Companies envision the opportunities for the graduates of the REnEW program to also evolve.

6.4.2.1.4 REnEW Program Overall Summary

The REnEW program is a great example of the holistic approach the Companies have taken in their activities that serve British Columbia's low income sector. By working with non-profit social agencies and skilled trade experts we are not only having a positive impact on the capacity within the energy efficiency trade sector, but also providing opportunities for individuals that are facing barriers to employment to overcome their barriers. Further, by collaborating and partnering with utilities and non-profit social agencies, we are able to lead this initiative in a very cost efficient manner.

6.4.2.2 Energy Saving Kit Program

6.4.2.2.1 Energy Saving Kit Program Overview

Energy Saving Kit Program	
Target Audience	Low Income Residential Retrofit Customers
Duration	Jul 1, 2010 - Dec 31, 2011
Incentive	Kits delivered at no cost to program participants Approximate retail value of the kit is $75
Partners	BC Hydro FortisBC Inc. will be added in 2011
Overview	
Background	The Energy Saving Kit ("ESK") program is the first widely available low income program for the Companies. By partnering with other utilities, the process is simplified and administration and marketing costs are reduced. The ESK offer is a broadly marketed and easily accessed program available to customers in all utility partners' regions, regardless of their fuel type. Based on the qualification of a customer's application, instructions are sent to a supplier to send out the kit. The eligibility criterion is consistent across utilities and is based on the participants' household income. The definition of low income customer for this program is based upon Statistics Canada low income cut-offs ("LICOs"). The kit is delivered at no cost to the participants and includes several easy to install energy savings measures, such as water heater pipe wrap, low flow showerheads, faucet aerators, weather stripping, foam tape for door draft-proofing, and other measures. The ESK also includes educational brochures that will help customers reduce their energy consumption through simple behavioural

	changes. Although ESKs are most often mailed to individual participants, there are also options that allow non-profit housing societies and First Nation bands to apply on behalf of their tenants and receive a bursary. The bursary (currently administered through BC Hydro) allows the society or band to hire an individual to install the kits for their tenants. Currently, customers must call to apply for the program. In 2011, an online form will be created that is expected to enhance the application process and reduce administration costs associated with the telephone application channel.
Description	The ESK is a bundle of easy to install energy saving measures and is delivered to the participants' home free of charge.
Goals	• Make energy efficiency more accessible to low income customers by addressing the key barriers to energy efficiency in this sector (including affordability, availability, and awareness). • Provide low income customers with the opportunity to reduce their energy consumption, which will also reduce their energy bills and GHG emissions. • Enable low income participants to self-install energy efficiency measures in their homes. • Create a culture of conservation through increased knowledge and awareness of conservation behaviours. • Provide energy savings for the Companies.
Implementation	
Administration	BC Hydro, Consumer Response Marketing
Communications	The main communication channels used in 2010 were bill inserts and print ads in free community newspapers. Through BC Hydro, we are also reaching participants through food banks and a promotional letter to the clientele of the Ministry of Housing and Social Development.
Evaluation Strategy	Evaluation of the savings of the gas measures within the ESK is based on engineering calculations and third party studies. Further, we are able to leverage BC Hydro's evaluation of the ESK, which includes surveys to participants to confirm assumptions with respect to installation rates, free-ridership, and the popularity of various measures.

6.4.2.2.2 2010 ESK Program Results

In the first six months of the ESK program, over 5,200 participants have qualified for the program and received ESKs. This is a very strong response and reinforces that there are great opportunities for providing meaningful programs to our low income customers. Because this program has a very simple process and most of the administration of the program is performed by BC Hydro, the Companies' costs are low and the energy savings are high overall. This resulted in a high TRC score of 2.3.

Table 6-8: 2010 ESK Program Actuals

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	4,206	$39	$44	2,637	15,520	27%	2.3
FEVI	1,052	$10	$11	660	3,959	27%	2.4
Total	5,258	$49	$55	3,297	19,479	27%	2.3

The Companies partner with other utilities in this program. One of the benefits in partnering with other utilities to administer EEC programs is the cost efficiencies of shared program evaluations. In 2010, BC Hydro performed an evaluation of the Energy Saving Kit program and there were two significant findings that impacted the above results. First, due to higher than expected installation rates of various measures that reduce gas consumption, the energy savings per kit is higher than what was anticipated at the onset of the program (0.86 GJ/kit vs. 0.46 GJ/kit). Second, free-ridership in the program was greater than anticipated at 27 percent. Some of the reasons suspected for high free-ridership include the low cost of some of the individual items in the kit, general familiarity with the energy savings benefits of items in the kit, and a desire by the surveyed population to be seen as socially responsible by the interviewer (i.e. reporting bias). In spite of the deemed free-ridership, by virtue of participating in this program, low income customers are exhibiting socially desirable energy efficiency behaviours, which fits with the Companies' overall objectives as well as the objectives of British Columbia's social and environmental policies.

6.4.2.2.3 2011 ESK Program Performance Forecast

The successful enrolment of low income participants in the ESK program in 2010 is expected to continue throughout 2011. We will make adjustments to the measures in the kits based on the evaluation performed in 2010 in order to supply more of the measures that are being utilized and remove measures that are not being utilized adequately. In 2011, we will be able to offer all our low income customers an internet-based application process, which is expected to expand our reach while also reducing call centre costs.

The following table shows the forecast result of the continuation of the program in 2011, continuing with a positive TRC ratio of 2.2 for the program.

Table 6-9: 2011 ESK Program Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	8,400	$88	$98	5,267	31,271	27%	2.2
FEVI	2,100	$22	$25	1,317	7,903	27%	2.3
Total	10,500	$110	$123	6,584	39,174	27%	2.2

6.4.2.2.4 ESK Program Overall Summary

The ESK program is the Companies' first broadly available EEC program in the Conservation for Affordable Housing category and the program has received outstanding response from our customers. In half a year over 5,000 customers have participated in the program. In 2011, we will continue to collaborate with our utility partners on our marketing and communication efforts, thereby achieving further cost efficiencies and greater reach. By partnering with BC Hydro in 2010 and FortisBC Inc. in 2011, we are ensuring that through this program our low income customers are served in a streamlined fashion that minimizes the customer's effort and the utilities' administration costs.

6.4.2.3 Ministry of Energy and Mines Low Income Partnership Grant Program

6.4.2.3.1 Ministry of Energy and Mines Low Income Partnership Grant Program Overview

Ministry of Energy and Mines Low Income Partnership Grant Program	
Target Audience	New Construction / Retrofit
Duration	To be invested by Mar 31, 2012
Incentive	Varies
Partner	Ministry of Energy and Mines

Overview	
Background	On March 31, 2009, through the Low Income Partnership Grant agreement, the Ministry of Energy and Mines awarded FEI and FEVI a grant of $5.155 million to support and develop DSM programs for low income individuals in BC. These funds are incremental to the funds approved in the EEC Decision. This grant stipulates that: • $1 million is to be used to deliver the Super Efficient New Construction program; • $1.5 million is to be used to support BC Hydro's low income programs; • $954,189 is to be used to fund retrofits under the LiveSmart BC Carry Over project; and • $1,700,811 is to be used to develop new programs for low income customers.
Goals	• Encourage energy efficient new construction that far exceeds the current building codes. • Achieve deep energy savings in low income units. • Reduce GHG emissions.
Implementation	
Administration	The Companies
Communications	The intention is to issue press releases at various milestones in the project. In 2011, we will issue a press release when the SENC project is fully committed.
Evaluation Strategy	The SENC project's energy performance will be measured over time to validate the savings expected. The $1.5 million used to support BC Hydro's low income programs will be specifically contributed to BC Hydro's Energy Conservation Assistance program and will be evaluated alongside the general evaluation of that program. The Livesmart BC Carry Over project was evaluated based on modelled energy savings. (Note: TRC calculations were not required by the Ministry of Energy and Mines for this project and the evaluation was carried out by the delivery agent that was contracted to complete the work.) The new energy efficiency programs the $1,700,811 is to be invested in are still under development.

6.4.2.3.2 <u>2010 Ministry of Energy and Mines Low Income Partnership Grant Program Results</u>

In 2010, the SENC component of the Low Income Partnership Grant program made good progress. Through the SENC program, four projects have received a total of $515,000 to advance their developments, and these four projects will each receive an additional 20 percent contribution at completion of their projects. The Livesmart BC Carry Over project was completed in 2009. This project involved energy efficiency retrofits in six building complexes (557 units) throughout the Lower Mainland. Total modeled energy savings from the project was 5,026 GJs (as reported by Eaga Canada).

The table below shows the funding amount and the investments already made.

Table 6-10: 2009-2010 Program Investments

Funding Components	Funding Agreement Amounts	Funds Invested at Dec 31, 2010
SENC	$ 1,000,000	$ 515,000
BC Hydro	$ 1,500,000	$ -
LiveSmart CarryOver	$ 954,189	$ 954,189
New DSM Projects	$ 1,700,811	$ -
Total	**$ 5,155,000**	**$ 1,469,189**

The SENC Program Oversight and Evaluation Committee, chaired by the Ministry of Energy and Mines, includes representatives from the Companies, BC Hydro, and FortisBC Inc. This committee is currently exploring other projects to invest the remaining $353,000 of uncommitted funds in the SENC project.

6.4.2.3.3 2011 Ministry of Energy and Mines Low Income Partnership Grant Program Forecast

In 2011, the Companies intend to form a partnership with BC Hydro on their Energy Conservation Assistance program. Substantial progress towards forming this partnership has already been achieved. The Companies intend to invest both grant funds and EEC funds in this program in 2011. The Energy Conservation Assistance program is described in the following section of this report.

Several avenues are being explored and researched to develop new DSM projects to invest the remaining $1,700,811. One avenue of research is with respect to opportunities within the mobile home segment of BC. The research is described further in Section 6.4.3.3. Also, information is being gathered on specific low income buildings in the Okanagan corridor to assess opportunities for deep retrofits in buildings that are not currently being served by any utilities' DSM programs.

6.4.2.3.4 Ministry of Energy and Mines Low Income Partnership Grant Program Summary

The Companies continue to facilitate the investment of the Ministry of Energy and Mines Low Income Partnership Grant in low income units across BC. In 2010, investments in the SENC program were achieved and some research is being conducted on opportunities for investing the remaining unallocated funds. As well, the Companies expect to be able to invest $1.5 million in a partnership with BC Hydro on the Energy Conservation Assistance program, which will see investments from this grant as well as the Companies EEC funds.

6.4.3 PROGRAMS IN DEVELOPMENT

6.4.3.1 Energy Conservation Assistance Program ("ECAP")

6.4.3.1.1 ECAP Overview

Energy Conservation Assistance Program ("ECAP")	
Target Audience	Low income residential retrofit customers Applies to renters (with landlords consent) or homeowners in single family dwellings or row housing
Duration	One year to confirm business case assumptions with the intention of extending the program indefinitely
Incentive	The average incentive per participant is $1,765 worth of installed measures in their home
Partner	BC Hydro
Overview	
Background	The Energy Conservation Assistance Program ("ECAP") is positioned to be the Companies' flagship program that achieves the deepest levels of energy savings in low income homes. ECAP is a targeted program that, in its current state, is offered only by BC Hydro to low income electricity customers. The Companies intend to participate in this program and broaden the program's reach and impact to include low income natural gas customers. The Companies also intend to eventually expand the types of retrofits that are performed through this program to include items such as furnace filters and new high efficiency furnaces. Due to the fact that low income customers often have priorities other than learning about or implementing energy efficiency in their homes, this program takes a unique approach to making it easy for customers to participate. This involves a straightforward, single application process, which is used by both BC Hydro and the Companies to qualify the participants, and, once the participants qualify, they are fully serviced by the ECAP program's delivery agents. All the participant needs to do is receive the calls from the delivery agents and be home at an agreed upon time to start receiving the benefits of the program's services. Quality assurance of the retrofits will be performed through an independent third party contractor and is performed on 10 percent of the homes that receive basic measures (i.e. low flow showerheads and light bulbs) and 20 percent of the homes that receive more advanced measures (i.e. insulation, draft proofing, and furnaces).
Description	The program involves a visit to the participant's home, an assessment of the energy savings opportunities, and the installation of a host of energy efficiency measures. Education on energy conservation behaviour is also delivered during the initial visit to the customer's home.
Goals	• Enable approximately 2,400 low income participants annually to receive comprehensive energy evaluations in their homes and have

	a suite of energy efficiency measures installed. • Make energy efficiency more accessible to low income customers by addressing the key barriers to energy efficiency in this sector (i.e. affordability, availability, and awareness). • Provide energy savings for FEI/FEVI. • Provide low income customers with the opportunity to reduce their energy consumption, energy bills, and GHG emissions. • Create a culture of conservation through increased knowledge and awareness of conservation behaviours.
Implementation	
Administration	The primary administrator from the utility perspective is BC Hydro; however, the Companies will qualify participants that are the Companies' customers. The visits to customers' homes to perform energy assessments and retrofits are performed by independent delivery agents.
Communications	Prospects for the program are identified and engaged through working collaboratively with social housing providers and program delivery agents. Recipients of the ESKs are also prospects for participation in this program if they meet the minimum energy consumption criteria.
Evaluation Strategy	The intention is to perform a billing analysis of participants in the ECAP program once there are enough participants with minimum of one year post-installation consumption.

6.4.3.1.2 2011 ECAP Forecasted Program Results

The ECAP program is expected to launch by the end of Q2 2011; thus, figures shown below in Table 6-11 are estimates based on six months of the program being available in the market. The TRC score of 0.6 includes the full costs of the program including enabling costs such as carbon monoxide detectors, ventilation fans, and many costs that are unique to delivering a direct install low income program. These unique costs include such items as hiring contractors to perform the retrofitting work, costs of training the contractors on working in low income homes (sensitivity training), and ensuring contractors are well educated on the utilities' safety procedures and policies. These enabling costs and unique program costs have a detrimental effect on the programs TRC; however, they are critical to implementing this important program. This program is another example of work that needs to be performed in order to reach our province's carbon reduction goals, but is ineffectively evaluated using conventional TRC requirements.

The Ministry of Energy and Mines Low Income Partnership funding, described in the previous section, specifically directs the Companies to contribute $1.5 million towards BC Hydro's low income programming by March 2012 and this contribution is exempt from TRC requirements as agreed by the government. Therefore, in 2011, the Companies will apply at least a portion of the Low Income Partnership funding against the ECAP program costs. The program forecast shown below is reflective of the full costs of the program as this best illustrates the actual expected costs of the program.

Table 6-11: 2011 ECAP Program Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	960	$1,082	$613	5,548	53,242	4%	0.6
FEVI	240	$270	$153	1,387	13,089	4%	0.6
Total	1200	$1,352	$766	6,935	66,331	4%	0.6

6.4.3.1.3 ECAP Program Overall Summary

A program of this magnitude and complexity takes a considerable amount of coordination and administration. With much of the ground work laid in 2010, the Companies expect to be able to launch a joint ECAP program by Q2 2011 with BC Hydro. This program will represent an excellent opportunity for the Companies to achieve deep energy savings for our low income customers.

6.4.3.2 Co-operative Housing Federation of BC – Energy Performance Housing Inventory (Study)

Co-operative Housing Federation of BC (CHF BC) – Energy Performance Housing Inventory (Study)	
Target Audience	Retrofit, Co-operative Housing in BC
Duration	To be completed in 2011
Financial Contribution	$15,000
Partners	BC Hydro, BC Housing
Overview	
Research Goals	• Create a better understanding of current building stock conditions. • Provide an analysis of baseline building energy performance indicators. • Obtain the necessary information to develop comprehensive programs tailored specifically to the conditions of the co-operative housing sector. • Create a framework for determining buildings most in need of retrofit work. • Identify opportunities to achieve cost-effective energy savings.
Implementation	
Administration	CHF BC with sub-contracted services to City Green and Eaga Canada.
Background	The CHF's BC Energy Performance Housing Inventory is a first step towards addressing the complex nature of working within the co-operative housing

	sector. Co-operative housing is a challenge to engage in energy efficiency programming because of the following: 1) most co-operative housing complexes are separately governed (i.e. owned and operated independently), thereby requiring buy-in from the majority of tenants in each individual housing complex; 2) tenants in co-operative housing cannot all be assumed to have a low household income; and 3) the financial situation of each housing co-operative varies significantly. The one item that is most likely to be consistent across the co-operative housing sector is that energy efficiency is very rarely on their list of priorities. Since no comprehensive housing energy-use inventory exists for the co-operative housing sector in BC, the energy use characteristics of co-operative housing are largely unknown. This makes it very challenging to design programs for the sector. This inventory will allow for a strategic approach to be designed that will ultimately allow for the prioritization of energy retrofits in housing co-ops in BC.

6.4.3.3 Mobile Homes (Study)

Mobile Homes (Study)	
Target Audience	Retrofit, Mobile Homes in BC
Duration	To be completed in Q1 2011
Financial Contribution	$20,000
Partners	None
Overview	
Research Goals	• Identify the energy saving opportunities in mobile homes. • Create a better understanding of current building stock conditions. • Perform exploratory research to gauge attitudes and potential participation of mobile home owners in energy efficiency programs. • Determine the potential for upgrading mobile home furnaces to high efficiency furnaces, and the potential for converting oil furnaces to high efficiency natural gas furnaces. • Identify differences in income among those living in mobile homes. • Outline appropriate communication methods that will effectively reach individuals who live in mobile homes.
Implementation	
Administration	The Companies
Background	Mobile home owners are expected to be a segment of the population that are: • underserved by traditional DSM programming;

	• likely have lower than average income; and • likely to have higher than average elderly people. For the above reasons, the Companies have commissioned a survey to further explore opportunities that may exist in the mobile home sector.

6.5 Conservation for Affordable Housing Summary

The Conservation for Affordable Housing program area has been a priority for the Companies since the initial creation of our EEC Program principles. Our goal of creating programs that are accessible to all has already been achieved through the launch of our Energy Saving Kit program and the REnEW program in 2010. In the coming years, with energy prices generally increasing, the program area will become even more important. In 2011, the anticipated partnership with BC Hydro on the Energy Conservation Assistance program will see greatly expanded investment and a deeper level of savings for our low income customers. In 2011, the Companies will also be working with government to explore alternatives to TRC evaluation, and/or additional methods of measuring success of programs that serve our low income customers to ensure we can continue to create programs that achieve deep energy savings within the low income segment of BC.

7 JOINT INITIATIVES

7.1 Overview

Joint Initiatives are EEC programs that facilitate mutually beneficial partnerships between utilities and government partners or utilities and other utilities. These partnerships enhance EEC goals and provide value to customers through shared costs and efficiencies, streamlined communications, extended market reach across shared service territories, and a collaborative business model that incorporates a holistic view of the provincial energy landscape. Each utility and government partner has strong brand recognition and cost-effective marketing channels. Working together creates synergies that drive program participation and energy savings while optimizing administration and marketing resources. By sharing resources, a greater number of programs can be launched to serve the energy needs of our customers and the province as a whole.

As outlined in the 2009 EEC Annual Report, to further such Joint Initiatives programs, in July 2009 the Companies signed a Memorandum of Understanding ("MOU") with BC Hydro to facilitate increased utility collaboration on DSM. The purpose of the MOU is to drive efficiencies in program promotion and administration, thereby bringing education and incentive programs to residents and the trades across BC. The Companies are currently looking at the alignment of the Companies' EEC activities with sister company FortisBC Inc.'s PowerSense initiative with a view to achieving the same efficiencies and number of combined activities that the BC Hydro MOU has driven forward.

In Order No. G-36-09 on the Companies' EEC Application, the Companies received approval for $1 million in annual spending for Joint Initiatives as opportunities arose. Furthermore, in Commission Order No. G-141-09, as part of the FEI's 2010-2011 Revenue Requirements Application's Negotiated Settlement Agreement, the 2011 request for extension of 2010 residential joint initiatives program funding amounting to $1.346 million was approved. Similarly for FEVI, in Commission Order No. G-140-09, as part of FEVI's 2010-2011 Revenue Requirements Application's Negotiated Settlement Agreement, the 2011 request for extension of 2010 residential program funding amounting to $0.302 million was approved.

Program initiatives that were outlined and approved in the EEC Application included home energy assessments, home labelling, affordable housing, and Community Action on Energy Efficiency ("CAEE"). The Companies' contributions to home energy assessments and home labelling are implemented within the LiveSmart BC partnership with the Province of British Columbia. The affordable housing initiatives are deemed high priority and as such are referenced within their own program area (Refer to Section 6). In addition to the Joint Initiatives described within this section, the Companies have also engaged in significant collaboration with the Province on PSECA (Refer to Section 4.4.2.5) and with BC Hydro on the Energy Specialist program (Refer to Section 11.2.4). Although CAEE is now complete, the Companies collaborated on a number of additional initiatives with communities. In 2010, community programs included working with the City of Vancouver on a solar thermal water heating pilot, a weatherization pilot, and water savers in the Interior. In 2011, we are working with the City of Saanich and other municipalities on a weatherization and hot water conservation pilot. Other community outreach activities are highlighted in Tablex.7-1

Throughout 2010 program implementation and 2011 program planning, the integrated efforts of utilities, governments, and communities touched all EEC program areas. Table 7-1 outlines the extent of Joint Initiatives that are currently being undertaken across the program areas, with greater detail in their respective sections.

Table 7-1: Joint Initiatives Portfolio Across Program Areas

Program	Utility		Partners			
	FEI	FEVI	FortisBC Inc	BCHydro	Province	Others
RESIDENTIAL -Section 7						
LiveSmart BC Home Retrofits	X	X	X	X	X	
Weatherization Pilot - City of Vancouver	X			X		City of Vancouver
High Efficiency Appliances	X	X	X	X		
EnerGuide 80 - New Construction Program	X	X	X	X		
Water Savers - Ultra Low Flow Shower Heads	X		X			
Switch 'N Shrink - Variable Speed Motors	X	X	X	X		
CONSERVATION FOR AFFORDABLE HOUSING - Section 6						
Energy Savings Kits	X	X	X	X		FBC will be added in 2011
REnEW	X	X	X	X		John Howard Society, BladeRunners
Energy Conservation Assistance Program	X	X		X	X	2011 Program
Ministry of Energy Low Income Partnership - Super Efficient New Construction	X	X	X		X	Note: Non-EEC funding
COMMERCIAL - Section 4						
Spray Saver Program	X	X		X		Green Table Network Society
Continous Optimization Program	X	X		X		
Custom Design Program	X	X		X		
UBCO C.Op Program	X		X			
LiveSmart BC for Small Business	X	X	X	X	X	
Farm Pilot Energy Assessment	X	X		X		ARCORP
INNOVATIVE TECHNOLOGIES - Section 10						
Solar Water Heating PSECA Program	X	X				PSECA, SolarBC
Solar Air Heating PSECA Program	X					PSECA, SolarBC
NGV LNG Incentive Program	X					
SolarBC Schools Incentive Program	X	X				SolarBC
.80 EF Hot Water PILOT	X	X				Canadian Gas Association (CGA)
City of Vancouver MURB PILOT	X					City of Vancouver
Solar Residential Hot Water PILOT	X					City of Vancouver
INDUSTRIAL - Section 9						
Rogers Sugar Energy Balance Study	X			X		
MT & R Program	X			X		
Certified EE Pilot Plant Project	X		X		X	
CONSERVATION, EDUCATION AND OUTREACH - Section 8						
Sears Home Efficiency Audit	X		X			Sears
Water Savers and Weatherization		X				Regional District of Saanich
ENABLING ACTIVITIES - Section 11						
Energy Specialist Program	X	X		X		British Columbia Institute of Technology

In the Companies' 2009 EEC Application, the Joint Initiatives program area was primarily focused on the residential market and as such only residential joint initiatives have remained distinct from their program area. Only residential joint initiatives will be described in detail in Section 7.4, while joint initiatives in other program areas are contained within their respective sections as indicated in Table 7-1. The following sections provide information about individual programs including an overview of the 2010 program results and the outlook for 2011.

7.2 2010 Joint Initiatives Results

Table 7-2 provides a summary of the results of 2010 residential joint initiatives programs. Since a large portion of 2010 overall spending is attributed to LiveSmart BC home energy assessments for which we have not captured direct savings, it is difficult to present the program area in terms of TRC; rather these costs are rolled up into portfolio level expenses. The true measure of success is in the collaborative approach to program deployment that results in extended reach and reduced costs through shared resources as utilities and governments offer programs to BC residents.

Table 7-2: 2010 Residential Joint Initiatives Summary

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
LiveSmart BC - Home Energy Assessments (D-Visits) through LiveSmart BC - 2009-2010	349	16	365	No Direct Savings				
LiveSmart BC - 2010 -2011 Home Retrofit	No invoices were received in 2010 so energy savings not calculated							
Energy and Water Efficient Appliance Programs	7		7	2,801		2,801	0.8	
Water Savers Pilot	14		14	2,899		2,899	2.0	
City of Vancouver Weatherization Pilot	15		15	No Savings Claimed at this Time				
Non Program Specific Admin & Studies	48	8	56	N/A				
Total	**433**	**24**	**456**	**5,700**	**N/A**	**5,700**	**N/A**	

The highlights of 2010 residential joint initiatives programs are as follows:

The LiveSmart BC Efficiency Incentives program, a partnership with the Ministry of Energy and Mines and utility partners, is a key collaborative venture for home retrofits. The program illustrates the Companies' commitment to "whole home performance" and "house as a system" home energy management. The Companies have supported a variety of incentives upon each iteration of the program.

- From August 2009 through March 31, 2010 the Companies provided $75 for partial funding of home energy assessments, contributing to over 10,000 assessments and a total contribution of over $760,000.

- From April 2010 through March 31, 2011 the Companies have contributed partial funding to building envelope measures with a forecasted contribution of $657,000 and an estimate of 246,000 GJs saved over the lifetime of these measures. Since we did not receive invoices for the 2010 iteration until January 2011 neither costs nor savings were captured in the 2010 EEC portfolio and all forecasted savings will be reported in 2011.

In 2009 and 2010, FEI collaborated with FortisBC Inc. on programs for energy and hot water efficient washing machines. In addition, the Companies collaborated on the Water Saver's pilot that distributed ultra low flow showerheads to rural customers. FEI's participation extended the program's reach to customers heating water with natural gas.

The City of Vancouver Weatherization pilot was co-funded by the City of Vancouver, BC Hydro, and FEI to take an initial look at capacity building for the weatherization industry in both creating customer demand and servicing this demand with skilled practitioners. The program was also conducted in collaboration with EMBERS, a non-profit employment and self-employment development organization in the Downtown Eastside of Vancouver. The program combines the benefits of energy savings, green jobs, and training for individuals who may face barriers to employment.

7.3 2011 Joint Initiatives Outlook

For the purpose of consistency, in the 2011 outlook, the Joint Initiatives program area will continue to focus on the residential market, with some limited discussion of a commercial area joint initiative that is in a preliminary design stage. Table 7-3 provides an overview of 2011 residential joint initiatives programs that include LiveSmart BC and ENERGY STAR® washer programs with utility partners.

Table 7-3: 2011 Joint Initiatives Outlook

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
LiveSmart BC - 2010 -2011 Home Retrofits	616	42	657	234,273	11,731	246,004	1.1	1.0
LiveSmart BC - 2011 -2012 Home Retrofits	1,758	178	1,935	431,354	43,367	474,721	1.0	1.0
LiveSmart BC - 2011 - 2012 for Small Business	Under Development							
Home Efficiency Web Portal	50	10	60					
Energy and Water Efficient Appliance Programs - BCHydro & FortisBC Inc	359	71	430	149,200	31,613	180,813	1.0	1.0
Non Program Specific Admin & Studies	160	40	200					
Total	**2,942**	**340**	**3,282**	**814,827**	**86,711**	**901,538**	**0.9**	**0.9**

Joint initiatives under development in 2011 will continue to provide value to customers through shared resources and communications channels.

Activity for LiveSmart BC in 2011 includes:

- Completing the April 1, 2010 through March 31, 2011 iteration in which we forecast $657,000 in spending and 246,000GJs in savings;
- Launching the April 1, 2011 through March 31, 2012 iteration (currently under development), which will focus on enhancing building envelope measures from the 2010 iteration;
- Developing and launching a Home Energy Efficiency online portal that will provide a One Stop Rebate shop, and information and tools that promote home energy efficiency retrofits; and
- Assessing the opportunity to participate in the LiveSmart BC small business program in the Commercial Program Area. Please see Section 1.4.2.1.4 for information on LiveSmart BC for small business.

We are launching a high efficiency washer rebate program with electric utilities in each of their service territories. Section 7.4 provides further detail about individual programs including goals, 2010 results, and the outlook for 2011.

7.4 Joint Initiatives Program Details

7.4.1 COMPLETED PROGRAMS

7.4.1.1 City of Vancouver Weatherization Pilot

7.4.1.1.1 City of Vancouver Weatherization Pilot Overview

City of Vancouver Weatherization Pilot	
Target Audience	Residential Retrofit Customers
Duration	Fall 2010
Support	$15,000 contribution to provide training and weatherization services to about 50 homes in the City of Vancouver
Partners	City of Vancouver, BC Hydro, FEI, and EMBERS, a non-profit employment and self-employment development organization in the Downtown Eastside of Vancouver

<table>
<tr><th colspan="2">Background</th></tr>
<tr><td>Description</td><td>The City of Vancouver, BC Hydro, FEI, and EMBERS are piloting a weatherization/air-sealing business model. The program will train unemployed, bondable Vancouver residents to undertake air-sealing work in homes. The service will include a before and after blower door test to track performance improvements in each home.</td></tr>
<tr><td>Goals</td><td>The primary objectives of the pilot program were to:
Create local capacity in energy efficiency for basic air sealing and draft proofing, also known as home weatherization. Currently there are very few trained providers of these services and an opportunity exists to develop this industry and educate consumers about the benefits of this service;
Prove the energy savings that result from weatherisation (or air-sealing) in homes as inputs to utilities' cost/benefit models for development of DSM programs;
Identify a business model for providing these services to determine the following: what tasks are involved in air sealing, amount of time it takes, the market potential, the potential cost of the services, and to what extent homeowners are willing to pay for air sealing services; and
Work with a social enterprise to determine if these skills can be readily taught to those facing employment barriers such as REnEW graduates.
The longer term goal for the City of Vancouver was to prove the effectiveness (energy efficiency/savings) and the economic viability of a weatherization/air-sealing business, and to seed a stand-alone business that will offer job opportunities and career development for inner-city residents. The longer term goal of the Utilities was to determine if this training model can be used in other communities across the province.</td></tr>
<tr><th colspan="2">Implementation</th></tr>
<tr><td>Administration</td><td>City of Vancouver</td></tr>
<tr><td>Communications</td><td>Community marketing and earned media was used to attract participants and increase program awareness.</td></tr>
<tr><td>Evaluation Strategy</td><td>Program results are being analyzed to understand the energy savings associated with draft proofing. The Companies will be conducting consumption data analysis in the future.</td></tr>
</table>

7.4.1.1.2 Program results and future outlook

The pilot was successful in defining what the weatherization process entailed, average length of the job, and energy savings potential. A core staff was trained and experience was gained through the completion of air sealing approximately 50 homes. City of Vancouver and Downtown Eastside funding has been obtained to launch a stand-alone business for weatherization that employs individuals facing barriers to employment.

The utility partners and the Ministry of Energy and Mines are discussing ways these results can be used to support training for the industry and ways the intelligence gained from the pilot can be used in other communities across the province.

7.4.2 ACTIVE PROGRAMS

7.4.2.1 LiveSmart BC Efficiency Incentives Program (Home Retrofit Program)

The LiveSmart BC Efficiency Incentives program section presents the background, the Companies contributions to date, and the 2011 outlook for LiveSmart BC yearly iterations.

7.4.2.1.1 LiveSmart BC Background

LiveSmart BC Efficiency Incentives – Home Renovation Program	
Target Audience	Residential Retrofit Customers
Incentive	September 2008 through December 2009 - $250 incentive for ENERGY STAR® heating system upgrade – Please refer to Section 3.4.1.1 for details August 16, 2009 through March 31, 2010: Home Energy Assessments (D-visits) $75 subsidy from utility partner (based on fuel source) and $75 subsidy from Ministry of Energy and Mines April 1, 2010 through March 31, 2011: Utility partner contributions for air sealing, insulation, and windows (supplemented by the Ministry of Energy and Mines) April 1, 2011 through March 31 2012 – under development
Partners	FEI, FEVI, BC Hydro, FortisBC Inc., and Ministry of Energy and Mines
Background	
Background	The utility partners, FEI, FEVI, BC Hydro, and FortisBC, are collaborating on a BC Home Retrofit project through the Ministry of Energy and Mines' LiveSmart BC Efficiency Incentive program. The primary objective of the collaboration is to develop a platform that is sustainable and can remain in the market for many years without relying on the contribution of any one partner, including the provincial or federal government. In addition to consumer incentives, the utility partners are developing a longer term vision to jointly fund education and outreach, working to engage consumers and the trades in energy efficient retrofits.
Goals	• To develop a platform that is sustainable and will remain in the market for many years without being reliant on the contribution of any one partner. A key component of the sustainable platform is to develop a common back-end for program administration and customer support. • To utilize the cost-effective marketing channels of individual utilities and the government while developing an integrated marketing plan that optimizes outreach and drives program participation. Consumer education and outreach will be a key component in addition to the incentive offering. • Through education, create consumer demand for energy efficient retrofits, thereby driving the industry in the process.

	• A longer term strategy is to engage the trades in education and outreach that will support the promotion of energy efficiency. • To create a Home Energy Efficiency online web portal and One Stop Rebate shop that will centralize offers from utilities, provincial, municipal and federal governments, and associations.
Implementation	
Administration	Ministry of Energy and Mines – LiveSmart BC
Communications	Through individual partners' communications channels – FEI, FEVI, Ministry of Energy and Mines, BC Hydro and FortisBC Inc.

7.4.2.1.2 <u>The Companies' Contribution for EcoEnergy Home Energy Assessments Through LiveSmart BC</u>

As a result of the success of the original LiveSmart BC offer in 2008, the program was oversubscribed as of August 2009. At that time, the Companies joined the electric utilities, BC Hydro and FortisBC, in providing a $75 subsidy for EcoEnergy Home Energy Assessments. The Companies subsidized a total of 10,236 assessments for a contribution of $768,000 from August 16, 2009 through March 31, 2010, which is the provincial fiscal year end. Table 7-4 provides an overview of participation for FEI and FEVI. Due to the nature of this project, in that the assessment is an evaluation step only, the Companies recognize that no energy savings can be claimed directly as a result of this program. Rather, the home energy assessment is an avenue into other retrofit incentives that result in energy savings.

The following Table 7-4 shows the Companies subsidized over 10,000 home energy assessments for a $768,000 contribution to customers participating in the LiveSmart BC program.

Table 7-4: 2009-2010 Overview of Home Energy Assessment Contributions for LiveSmart BC

	Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)
2009 Invoices - *	FEI	5,182	389	-
	FEVI	263	20	-
2010 Invoices - *	FEI	4,596	345	4
	FEVI	195	15	1
Total	FEI	9,778	733	
	FEVI	458	34	
Program Total		10,236	768	5

* Participant counts from Ministry of Energy and Mines' invoices based on NRCan D- visit data

7.4.2.1.3 LiveSmart BC 2010 Results for Building Envelope Incentives

In the LiveSmart BC program iteration that launched April 2010, the Companies, in collaboration with BC Hydro and FortisBC, provided partial payment of the building envelope rebates including air sealing, insulation, and windows. There were no invoices in 2010 and therefore no energy savings or costs were claimed. Based on information available at the time of writing this report, a $657,000 contribution is forecasted, which should result in approximately 246,000 GJs of savings over the lifetime of these measures as outlined in Table 7-5.

Table 7-5: LiveSmart BC 2010 Forecasted Program Results

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	2,156	531	85	21,463	234,273	12%	1.1
FEVI	108	27	15	1,075	11,731	12%	1.0
TOTAL	2,264	557	100	25,609	246,004	12%	1.1
Note: The forecasted participant counts and savings are an estimate since there is a time lag between data transfer from service organizations, NRCan and the Ministry invoicing utilities. Only one invoice has been received to date for an estimated 25% of the activity. This invoice amount was multiplied by 4 to provide the above forecast.							

7.4.2.1.4 2011 Outlook

The LiveSmart BC iteration launching April 2011 is under development, with the prospect of remaining in market for two years depending on BCUC funding approval for the 2012 Joint Initiatives program area. Based on information available at the time of writing this Report, we forecast a $1.8 million incentive expenditure which would result in approximately 475,000 GJs of savings over the lifetime of these measures as outlined in Table 7-6. Please note these are very preliminary forecasts and the final offer is still under discussion with the Ministry of Energy and Mines, BC Hydro and FortisBC Inc.

Table 7-6: LiveSmart BC 2011 Outlook

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	5,097	1,596	162	40,503	431,354	12%	1.0
FEVI	510	160	18	4,070	43,367	12%	1.0
TOTAL	5,607	1,755	180	44,573	474,721	12%	1.0
Note: The forecasted participant counts and savings are an estimate at the time of writing.							

To complement the LiveSmart BC partnership, the Companies are also working with BC Hydro and FortisBC Inc. to develop a Home Energy Efficiency online portal that will provide a One Stop Rebate shop, information, and online tools that promote home energy efficiency retrofits.

LiveSmart BC partners are also jointly funding energy modeling studies to support the residential retrofit market. These studies include energy modeling to ensure common archetypes were used in LiveSmart BC cost benefit tests, a survey of existing residential housing stock to determine energy usage for various segments of electric and gas heated homes, research into Hot 2000 modeling to provide NRCan with verified energy savings based on regional consumption data, and initiatives to define Hot 2000 standard operating conditions for the province. LiveSmart BC partners are also working collaboratively to develop programs to train and engage contractors in promoting energy efficiency (Please refer to Section 11.2.2).

In February 2011, the LiveSmart BC program also began encouraging reduced energy consumption among small commercial customers. The Companies are working with the Ministry of Energy and Mines to elaborate a framework for collaboration on the delivery of incentives to reduce natural gas consumption. Program design is in the initial stages and has not yet been completed, nor have specific objectives been established. The initial proposal is centred on the Ministry providing "Top-up" incentives to the Companies' current product rebate offerings. The Companies will continue to work with the Ministry of Energy and Mines to finalize a detailed strategy to encourage reduced natural gas consumption among small businesses.

The LiveSmart BC program, which is a collaboration between the Ministry of Energy and Mines, FEI, FEVI, FortisBC, and BC Hydro, provides significant customer value in engaging BC households and small businesses in energy efficient retrofits. Through shared resources and administrative support by the Ministry of Energy and Mines, British Columbians can participate in a cost-effective program that serve the greater good of the energy needs of the province by supporting retrofits and their associated GHG emissions reductions.

7.4.2.2 Water and Energy Efficient Appliance Programs

7.4.2.2.1 ENERGYSTAR® Elite Tier 4 Washer Program Overview

Water and Energy Efficient Appliance Programs	
Target Audience	Residential Retrofit Customers
Duration	2010 - FortisBC Inc.: June 15 - Aug 15, 2010 2011 - FortisBC Inc.: Apr 1 - Dec 31, 2011 2011 - BC Hydro: Apr 1 - Dec 31, 2011
Incentive	2010 - FortisBC Inc.: $50 rebate per Tier 3 ENERGY STAR® clothes washer 2011 - BC Hydro and FortisBC Inc: $75 rebate per Tier 4 ENERGY STAR® clothes washer

Partners	FortisBC Inc. and BC Hydro
Background	
Background	Promoting the most energy and water efficient appliances is an important part of the EEC domestic hot water strategy. To do so most effectively, we are partnering with electric utilities, BC Hydro and FortisBC Inc., to extend the reach of the 2011 ENERGY STAR® appliance program to homes with natural gas water heaters. Clothes washers consume as much as 5-7 GJs/yr, representing 22% of residential DHW use (CPR, 2010). Qualifying ENERGY STAR® clothes washers use less energy and consume 35% to 50% less water than qualified washers made before January 1, 2007[37]. To encourage the most energy and water efficient models, the ENERGY STAR® brand has continuously improved their guidelines. The Modified Energy Factor ("MEF") is the current energy efficiency measure for all clothes washers, while the Water Factor ("WF") measures the water efficiency in gallons. The most energy and water efficient models will have the highest MEF value and the lowest WF rating. As a result of the 2011 ENERGY STAR® requirements, the majority of qualifying models will be front loading, which use less hot water, less mechanical energy, and result in dryer energy savings due to faster spin cycle speeds (CPR, 2010). Tier 4 is the Consortium of Energy Efficiency's highest energy efficiency designation for the most energy and water efficient models available in the marketplace. Qualifying Tier 4 clothes washers must have a minimum MEF $\geq$ 2.4 and a maximum WF < 4.0. Tier 4 models far exceed the 2011 ENERGY STAR® guidelines. Federal regulations do not require maximum WF ratings for appliances. By effectively educating consumers about the advantages of ENERGY STAR® appliances, the program will provide an opportunity to transform the market and encourage manufacturers to produce energy and water efficient clothes washers that meet or exceed the 2011 ENERGY STAR® requirements. In partnership with the electric utilities, the Companies are able to provide an increased incentive for Tier 4 ENERGY STAR® clothes washers while sharing marketing and administration costs to provide a cost effective program.
Description	In 2009 and 2010 FEI partnered with FortisBC Inc. to provide incentives for Tier 3 ENERGY STAR® clothes washers to extend the reach of their program to homes with natural gas water heaters. As the washing machine market is transforming and ENERGY STAR® base levels are increasing, the 2011 program provides rebates for an elite selection of Tier 4 models with a MEF $\geq$ 2.4 and a maximum WF < 4.0, to continue to positively impact efficiency standards with manufacturers. In 2011, FEI will partner with FortisBC Inc. and BC Hydro in their respective territories to provide a $75 consumer rebate. FEI and FEVI will provide $50 of this rebate for all residents with natural gas water heating.
Goals	• Capture the energy savings associated with promoting the most energy and water efficient ENERGY STAR® clothes washers. • Through utility collaboration, provide a province-wide program for 2011.

[37] 2010 EnerGuide Appliance Directory, NRCan Office of Energy Efficiency as part of ecoENERGY, an ecoACTION initiative.

	• Increase residential customers' knowledge and awareness about energy efficiency and conservation regarding laundry such as: o ENERGY STAR® washers are energy and water efficient; o Cold water wash decreases DHW energy use; and o Hanging clothes to dry decreases electrical energy use.
Implementation	
Administration	Electric utilities - FortisBC Inc. / BC Hydro
Communications	Program promotion through appliance retailers, community events, an online contest, and the Companies' marketing channels.
Evaluation Strategy	Research will be conducted to confirm energy savings claims for natural gas water heating.

7.4.2.2.2 2010 Program Results

As outlined in Table 7-7, based on 130 participants, the program achieved annual gas savings of 210 GJs and a projected 2801 GJs of savings over the lifetime of the measure. The TRC is marginal based on the estimated natural gas savings associated with the Tier 3 washers and relatively low participant numbers.

Table 7-7: FortisBC Inc 2010 ENERGY STAR® Washers Program Summary

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	130	7		210	2,801	10%	0.8

7.4.2.2.3 2011 Program Performance Forecast

In addition to partnering with FortisBC Inc., the Companies will collaborate with BC Hydro's province-wide 2011 ENERGY STAR® appliance program. The program will support the new 2011 ENERGY STAR® requirements through incentives for elite Tier 4 ENERGY STAR® clothes washers with MEF $\geq$ 2.4 and a maximum WF < 4.0. Regardless of the fuel type for DHW, Tier 4 ENERGY STAR® clothes washers will provide both electric and gas savings. FEI and FEVI will contribute $50 of the total $75 incentive for those homes with gas water heaters and the electric utilities will provide the remaining incentives.

Based on the BC Hydro forecast, the Companies expect to contribute to 6,300 residential incentives. Based on the FortisBC Inc. forecast, we expect 1,000 residential incentives. As illustrated in Table 7-8, the program is expected to achieve 20,805 GJs of annual energy savings given a 5 percent free rider rate. The free rider rate is lower for this program compared to the 2010 FortisBC Inc. laundry campaign since the 2011 appliance program supports a higher tier of ENERGY STAR® clothes washers with a lower market penetration.

Table 7-8: 2011 Tier 4 ENERGY STAR® Clothes Washer Program Forecast

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
BC Hydro Partnership							
FEI	5,040	$252,000	$42,000	14,364	124,498	5%	1.0
FEVI	1,260	$63,000	$8,000	3,591	31,124	5%	1.0
FortisBC Inc. Partnership							
FEI	1,000	$50,000	$15,000	2,850	24,702	5%	0.9
Total	7,300	$365,000	$65,000	20,805	180,324	5%	1.0

7.4.2.2.4 Overall Summary

Energy efficient appliances will result in both electric and gas savings regardless of the fuel type of a domestic hot water heater. These front load washers also result in 35-50 percent water savings as a non-energy benefit to the program. Therefore, partnering with FortisBC Inc. and BC Hydro enables the Companies to provide a province-wide program that will effectively educate consumers about the importance of water and energy efficient appliances, while sharing marketing and administration costs for a cost-effective program. With the overall TRC of 1.0, the Companies believe washer efficiency is an important component to the EEC domestic hot water strategy. In addition to natural gas savings, the opportunity to educate customers about hot water conservation and efficient laundry practices provides many benefits to our customers.

7.4.2.3 FortisBC. Water Saver Pilot Program

7.4.2.3.1 Water Saver Pilot Program Overview

FortisBC Water Saver Pilot	
Target Audience	Residential Retrofit Customers
Duration	FEI: Sept 15 – Oct 31, 2010
Incentive	The distribution of free low flow showerheads
Partners	FortisBC Inc, FEI and ClimateSense

Background	
Background	As part of the EEC domestic hot water strategy, FEI collaborated with FortisBC Inc. to distribute free water saving kits within the communities of Castlegar and Kaleden to extend the reach of the Water Saver campaign to those homes with gas water heaters. According to the 2009 FortisBC Inc REUS Study, 37% of FortisBC Inc.'s customers do not have a low flow showerhead and would like to upgrade. The 2010 Conservation Potential Review ("CPR") has identified ultra low flow showerheads as being an important measure for our DSM programs. The showerheads within the water saving kits are not ultra low flow; however, their 1.5 GPM flow rate is comparable to the 1.25 GPM flow rate of an ultra low flow showerhead[38]. We will claim 1.0 GJ of gas savings per installation, a conservative estimate compared to the 2.0 GJ savings of an ultra low flow showerhead as outlined in the 2010 CPR. Both Castlegar and Kaleden were chosen based on their current vulnerability to water shortages due to low snow packs.
Goals	• Distribute 500 low flow showerheads to capture the associated energy savings for homes with gas hot water heaters. • Determine program participation rates and logistics for a 2011 province-wide program. • Increase the presence of EEC programs within rural service territories.
Implementation	
Administration	FortisBC Inc. and ClimateSense
Communications	Promotions included radio advertisements, print ads in community newspapers, the use of social networking sites, and online. Marketing collateral directed applicants to an online survey that captured the participant's space and hot water heating fuel type, number of CFL bulbs within the home, and the current number of low flow showerheads and ENERGY STAR® appliances.
Evaluation Strategy	Energy savings estimates to be confirmed through sub-metering projects.

7.4.2.3.2 2010 Results

Based on post survey results, the Water Saver program was well received within the small communities of Castlegar and Kaleden, and achieved a TRC ratio of 2.0. In total, both utilities distributed 1,000 low flow showerheads to promote hot water conservation while capturing significant energy savings.

[38] 2010 FEI/ FEVI Conservation Potential Review.

Table 7-9: 2010 Water Saver Program Results

Utility	Participants	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/Yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	500	7	7	420	2,899	16%	2.0

The program was successful in achieving its main objectives to distribute free low flow showerheads and to capture the associated energy savings. As outlined in Table 7-9 above, the program is expected to capture 420 GJs of annual energy savings and 2,899 GJs of savings over the lifetime of the measure. Based on post program survey results, 20 percent of participants had at least one low flow showerhead; however, these may be traditional low flow showerheads, which are less efficient fixtures than provided within the water saver kit[39]. As a result, a free rider rate of 16 percent was used for economic analysis. In 2011, the low flow showerhead measure will be incorporated into the Simple Home Efficiency Measures program for easy to install energy efficient upgrades within the home (Please refer to Section 3.4.3.1).

7.4.2.3.3 Overall Summary

The Water Saver campaign achieved its objectives in offering EEC activities within rural service territories while capturing the energy savings associated with low flow showerheads. In total, 1,000 water saver kits were distributed to residents within two communities that are particularly vulnerable to water shortages. The program was well received by the public since the showerheads were easy to install and the online application procedure was simple. In 2011, ultra low flow showerheads will be one of the measures in the Simple Home Efficiency Measures program since there are significant energy and water conservation benefits associated with this measure.

7.5 Summary

Joint Initiative programs provide numerous mutually beneficial advantages to all partners in the collaboration, and their customers. In working together, utilities and government partners can engage in more programs, extend the reach of incentives, provide cost-effective education and outreach, and generate even greater energy savings and GHG emissions reductions. Based on 2010 successes, the Companies are expanding their Joint Initiative projects in 2011 across all program areas, and in so doing, will provide a more robust energy efficiency program offering to the residents of British Columbia.

[39] 2010 FEI / FEVI Conservation Potential Review.

8 CONSERVATION, EDUCATION & OUTREACH (“CEO”) PROGRAMS

8.1 Overview

The Conservation Education and Outreach (“CEO”) program was designed to include general conservation and non-program specific communications. CEO initiatives support the EEC’s portfolio goals of energy conservation and GHG emissions reduction established by the Government of BC. This program area is also intended to foster and develop a culture of conservation within the province by educating customers about changing their mindset and behaviours in regards to conserving energy. The goal of these initiatives is to ensure customers learn about taking small steps towards energy conservation and that customers will be receptive to incentive programs when they are proposed. This section describes the principles behind the CEO initiatives, evaluation methods, 2010 initiatives by customer group, and programs in development for 2011.

8.1.1 DEVELOPING ENGAGING CEO INITIATIVES

In designing the CEO program area, the Companies were, according to the EEC Decision and Order G-36-09 (see page 21) in Appendix C, directed to review the CEO program area with a view to “altering the program to allocate funds away from the mass media campaign and to include other initiatives, with particular attention paid to conservation education within the school system and affordable housing initiatives.” In addition, as per section 44.1 (8) (c) of the *Utilities Commission Act*, R.S.B.C 1996, c.473, s.125.1 (4) (e), a public utility’s plan portfolio is adequate only if it includes an education program for students enrolled in the public utility’s service area. Furthermore, CEO initiatives follow many of the same program principles that were put forth in the EEC application, in particular:

- Programs will have a goal of universality; offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the Conservation for Affordable Housing initiative;
- Where possible, programs will be uniform across the service territories of the Companies, so customers will have equal participation opportunity; and
- Programs will be multi-year to create a sense of funding certainty necessary to effectively implement them in the marketplace.

Lastly, CEO activities include a diverse range of initiatives targeting various customer groups. The Companies consider many factors before settling on the right initiatives to pursue. These include, but are not limited to:

- Potential participant reach;
- Geographic spread across FEI and FEVI service territories;
- Demographics of event attendees;

- Media involvement such as print, online, radio, in-person, cooperative advertising, social media, or a combination thereof;
- Engagement level with customers that is activity-based vs. partnerships with third parties; and
- Reaching various customer groups such as children/students, residential customers, small businesses, large commercial/institutional customers, property managers for multifamily homes, low income customers, municipalities, and the general public.

The CEO initiatives undertaken in 2010 include very little mass media; instead, they target individual customer groups in consideration of that group's specific needs and include direct engagement and interaction with residential and commercial customers and students. Many of the initiatives are a continuation from 2009 since the development of several initiatives began that year. Table 8-1 provides a summary of the 2010 CEO initiatives that are active and in development in FEI and FEVI by customer groups. Table 8-2 summarizes the 2010 costs for the CEO program area. Much of the CEO funds in 2010 were spent on developing programs and messages to engage with residential customers and the general public. Conservation education programs are still in development stages for commercial and low income customers, and additional CEO programs are being developed for students and schools.

Table 8-1: Summary of 2010 CEO Initiatives

Program	Utility		Description	TRC	
	FEI	FEVI		FEI	FEVI
Active Programs					
Residential and General Public	X	X	Energy conservation education promoted through bill inserts, newspaper and magazine advertising, trade show guides, newsletters, directories, home shows, regional Canadian Home Builders' Association programs, ethnic material development, sports energy savings promotions, EEC Community Outreach, and employee outreach.	N/A	N/A
Commercial Customers	X	X	Energy conservation education promoted through newspaper and magazine advertising, trade show guides, newsletters, directories, trade shows, and seminars.	N/A	N/A
Conservation for Affordable Housing	X	X	Energy conservation education promoted through partnership with CHBA BC for Housing Affordability Symposium.	N/A	N/A
School Outreach	X	X	Various K-12 programs, competitions, and curriculum development educating students on energy conservation and providing resource materials to teachers.	N/A	N/A
Programs in Development					
Residential and Conservation for Affordable Housing Customers: Ethnic Outreach	X	X	Development of print and online materials for ethnic markets and develop partnerships with third party service providers for distribution and promotional channels.	N/A	N/A
Residential and General Public: Home Efficiency Measures Partnerships (Pilot Programs)	X	X	Efficient low-cost fixtures for programs for residential and multifamily customers leveraging on channels such as school programs, property management associations, and partnerships with municipalities, regional districts, and big box retailers.	N/A	N/A
Residential and General Public: New Construction Industry	X	X	Education, training sessions, and collateral development for builders/developers, showroom staff and salespeople, real estate, and home appraisal industries on high efficient gas appliances and home efficiency measures.	N/A	N/A
Commercial: Small Commercial Businesses Education Sessions	X	X	Education sessions with small businesses on energy conservation measures and related available resources.	N/A	N/A
Commercial: Health Authority Staff Engagement Pilot Program	X	X	Development of an online community site for health authority staff to learn about energy conservation actions they can take at work and home.	N/A	N/A
Conservation for Affordable Housing: BC Housing Tenant Engagement Pilot Program	X		Engage with BC Housing tenants in two Metro Vancouver sites through education on conservation behaviour relating to heat and hot water reductions.	N/A	N/A
School Outreach: BC Sustainable Energy Association	X	X	Educational workshops for elementary students on reducing C02 emissions and saving energy in the home and at school around the province.	N/A	N/A
School Outreach: Environmental Mind Grind	X	X	Student trivia competition on energy and environmental conservation for K-12 students around the province.	N/A	N/A
School Outreach: Post Secondary Program	X	X	Reviewing proposals from vendors such as GoBeyond, and looking into hiring an external consultant to develop and implement a CEO program.	N/A	N/A

Table 8-2: Summary of 2010 CEO Costs

	Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
CEO Portfolio Administration	$28	$4	$32	N/A	N/A	N/A	N/A	N/A
Residential and General Public Education and Outreach	$975	$143	$1,118	N/A	N/A	N/A	N/A	N/A
Commercial Customers Education and Outreach	$285	$28	$313	N/A	N/A	N/A	N/A	N/A
Conservation for Affordable Housing Education and Outreach	$8	$2	$10	N/A	N/A	N/A	N/A	N/A
School Outreach	$119	$24	$143	N/A	N/A	N/A	N/A	N/A
Total	$1,415	$201	$1,616	N/A	N/A	N/A	N/A	N/A

8.1.2 EVALUATION OF CEO INITIATIVES

CEO initiatives are not individually run through the California Standards Tests at a program level and do not have any energy savings directly associated with them; however, costs are included at the portfolio level in the overall EEC portfolio TRC. As several new CEO initiatives have been introduced into the portfolio, it has become increasingly important to evaluate the cost effectiveness of CEO initiatives in order to justify the expenditures associated with these activities. Possible methods to evaluate the effectiveness of CEO initiatives include advertising tracking, process evaluation, and web analytics; however, the specific method will be dependent on the type of CEO initiative implemented.

Advertising tracking can investigate the effectiveness of particular commercials or campaigns in terms of the recall of specific messages, changes in people's perceptions, and behavioural changes in the target audience.

Process evaluations measure the effectiveness of the program by assessing how well the program met a set of goals or metrics defined by the program administrators. This method has been used by other utilities and American state agencies such as Southern California Edison and Pacific Gas & Electric.

Examples of goals/metrics for educational and communication programs include:

- Increase student awareness of the relationship between energy and the environment; and
- Deliver at least two special events annually, during which the public is exposed to specific key messages and provided with information and materials.

Example of techniques used to assess whether goals/metrics are met include:

- Interviews with program staff;
- Survey of program participants and qualitative analysis of responses; and
- Focus groups of program participants.

Web analytics is the quantitative measurement of the relationship between visitors and a website. Simply put, web analytics is the process of understanding the Companies' online presence so that it can be optimized. The Companies work with Adobe Online Marketing Suite

Sitecatalyst, a remotely hosted, subscription-based solution for real-time website reporting and analysis. Codes are placed on web pages that execute when the page loads. As the page loads and the code on the page executes, a request is sent to the Sitecatalyst server for a web beacon, which is a two-by-two transparent pixel image. Along with this image request, the code collects and sends additional information to Adobe Online Marketing data centres. The data centres then populate a report with the collected data, which can be accessed by the Companies' web team, to allow them to analyze the web activity related to a specific CEO initiative.

For certain initiatives, such as event surveying, the Companies will hire an external research firm, relying on their particular methodology to complete the analysis. The Companies will also rely on the method recommended by an independent research firm depending on the CEO initiative. Modifications to improve the initiatives can take place after one or more of these forms of evaluation have been completed.

8.2 2010 CEO Initiatives by Customer Group

The activities that make up the CEO initiatives are designed to create and promote awareness, and educate the public on energy conservation. By encouraging customers to take small steps towards energy conservation with simple and low-cost behaviours, the Companies hope customers will later adopt or adjust their own conservation beliefs and install high efficient equipment through participation in our other EEC incentive programs. The CEO activities for 2010 are described in further detail below and grouped according to the following customer groups: residential customers, commercial customers, conservation for affordable housing customers, and schools.

8.2.1 RESIDENTIAL CUSTOMERS

With over 850,000 residential customers, it is vital for the Companies to provide them with energy saving information. This section outlines how CEO initiatives educate residential customers on conservation behaviours. It is the Companies' view that by providing education on behavioural changes, including low cost and no cost actions, this knowledge will assist customers to reduce their consumption and encourage them to pursue further efficiencies by participating in EEC incentive programs. According to the 2010 Customer Satisfaction Study conducted by TNS, three attributes were found to be key drivers of customer satisfaction with the conservation education provided by the Companies. These key drivers received an average or below average rating from participants.

- Provides information that helps customers use natural gas efficiently;
- Offers rebates for energy efficiency upgrades; and
- Is environmentally responsible.

Through the various EEC initiatives, the Companies will be able to meet customers' expectations about keeping energy costs within their budget through energy conservation education. It is important for the Companies to consider several diverse media channels in an attempt to reach the majority of residential customers. Energy conservation education is promoted through a variety of means, which have been grouped into five methods: print and online channels, home shows and events, the Energy Champion program, community outreach at community events, and via the Companies' employees. Below is a detailed description of each method.

8.2.1.1 Print and Online

Print and online publications are a cost-effective communications channel for delivery of information when compared to other communication channels such as television and mass media. The goal of the CEO program's print and online publications is to continually inform customers about various low-cost and no-cost behaviour changes they can adopt at home to reduce their energy consumption. In 2010, the Companies continued to provide information through customer bill inserts, print and online advertising in The Vancouver Sun's At Home section and community newspapers, and the Canadian Home Builders' Association's ("CHBA") publications, brochures, and ethnic material. The CEO program is also funding half the cost of a bill insert and bill message research study conducted by TNS Canadian Facts, with other departments in the Companies funding the other half. The purpose of this study is to determine readership levels, understand if certain messages garner more attention from readers than other messages, and the type of information desired by our customers. The primary targets for the study are residential and small commercial (i.e. Rates 2 and 3) customers, which are key audiences for EEC programs. The research firm, TNS, will test three waves of bill inserts through phone surveys. The study began in Q4 2010 and will be completed by Q2 2011.

8.2.1.2 Home Shows

Home shows remain an effective way to reach customers by creating opportunities for dialogue with customers on energy conservation. Based on the increasing number of customer inquiries regarding conservation, efficient technologies, and retrofit incentive programs from these events, the Companies strongly believe participation in home shows is an essential channel for educating customers about CEO initiatives and EEC programs.

The Companies have exhibited in home shows since 2006 and continued home show activity in 2010 by participating in home shows and CHBA events. The CHBA's regional branches represent the BC residential construction industry, and they liaise with local governments, promote the interests of housing and renovation consumers, and work to ensure a fair marketplace. In 2010, the Companies attended generally the same shows as the previous year and were in direct contact with over 35,000 residential attendees. The majority of the attendees at these home shows are homeowners specifically looking for home renovation and equipment upgrade information. Depending on the size, each show's total attendance can range from 5,000 to 45,000. For a complete list of 2010 home shows, please refer to Appendix E.

8.2.1.3 Energy Champion Program

The Energy Champion Program is a new initiative launched in Q4 2009 that continued into 2010, and is executed through partnerships with local sports teams such as the BC Lions, Vancouver Giants, BC Hockey League, and the Vancouver Canucks. The goal of this program is to educate children, youth, and the general public on energy conservation behaviour in a fun and rewarding manner, through a variety of methods including online competitions, face-to-face interactions, and pre and in-game activities. The activities with each sports team will differ slightly due to their own regulations and game formats. These activities are summarized in Table 8-3.

Table 8-3: Summary of CEO Energy Champion Promotions

Partnership	Description	Channel
BC Lions	Kids answer an energy conservation related question on bclions.com to enter to win tickets to a home game. One prize per BC Lions home game.	Online promotion on bclions.com
	Participants complete a race; they put on a sweater and run through a challenge course.	In game promotion
Vancouver Canucks	Individuals enter pictures of their ugliest sweater to win a pair of tickets to a Canucks game.	Online promotion on canucks.com
	Kids answer an energy conservation related question on canucks.com to enter to win a prize pack, including four tickets to Canucks Superskills.	Online promotion on canucks.com
	Sponsored in-game activation skill challenge - "Breakaway Relay."	In game promotion
Vancouver Giants	Kids answer an energy conservation related question on vancouvergiants.com to enter to win tickets to a Vancouver Giants home game.	Online promotion on vancouvergiants.com
BC Hockey League	In game and on-ice intermission activities and giveaways to promote energy conservation.	In game promotion

Partnering with regional sports clubs is an excellent way to reach out to families and the general public by raising the profile of our EEC programs and building up the Companies' conservation messaging. Sports fans are generally loyal and highly engaged with teams they identify with and support. These partnerships enable the Companies to leverage traditional media channels, such as television and radio, as well as the sports teams' online and social media channels. Because these channels are well developed in the market and have the ability to reach out to a large number of the teams' fans, they provide the Companies with easy and immediate access to an already engaged public audience. For instance, the Vancouver Canucks website obtained an average of 935,454 unique visitors per month over the course of 12 months; furthermore, they have over 154,016 Facebook fans and 26,365 Twitter followers.

As the Energy Champion program is still in progress, the Companies are in various stages of evaluating the program with the various sports teams. As summarized in Table 8-3, the Energy Champion program generally includes both in game and online web promotions. Web promotions can be easily tracked through web analytics on page views and contest signups via the sport team's website and the Companies' website. For a list of web analytics from the first year promotions with the sports teams, refer to Table 8-4. Since this was the first year for the Energy Champion program, there are opportunities to improve promotions in 2011.

Table 8-4: Web Analytics Comparing Various 2010 Energy Champion Promotions

BC Lions 2010 Season	Month	# Entries/Month	Lions Contest Page Views	Companies' Energy Champion # Page Views
Energy Champion Kids Promotion	Jun	15	282	38
	Jul	40	238	72
	Aug	35	141	56
	Sept	35	154	54
	Oct	40	142	119
Vancouver Canucks 2009-2010 Season	**Month**	**# Entries/Votes**	**Canucks Contest Page Views**	**Companies' Energy Champion # Page Views**
Ugly Sweater Promotion	Dec	39	50, 869	unrelated
	Jan	23, 098	(Facebook)	unrelated
Super Coaches Superskills Kids Promotion	Jan	1,270	3,329	62
Energy All Star Promotion online	Mar	1,443	3,710	unrelated
Vancouver Giants 2009-2010 and 2010-2011 Seasons	**Month**	**# Entries for Contest**	**Giants Contest Page Views**	**Companies' Energy Champion # Page Views**
Energy Champion Kids Promotion '09-'10 Season	Oct	23	243	n/a
	Nov	44	200	4
	Dec	29	146	55
	Jan	15	115	62
	Feb	8	52	19
	Mar	24	113	34
	Apr	18	115	48
Energy Champion Kids Promotion '10-'11 Season	Sept	n/a	58	54
	Oct	35	125	119
	Nov	20	110	305
	Dec	14	10	262

In 2010, the Companies also conducted a field intercept survey on our partnership with the BC Lions. Although the study had a small sample size, it provided insight into improvements that can be made to the program for delivery in 2011. The survey recommends employing a multi-channel approach to reinforce the Companies' messaging that includes the use of a media relations campaign, pre-game radio spots, video screen airtime, and a physical takeaway linked back to a website with contests that can be promoted through social media. Also, the results suggest the activities should engage in the crowd mentality and that taking advantage of the family section of the stadium would be beneficial. These insights are useful for the Energy Champion program as a whole, as many of the elements can be applied to activities with the other sports teams.

8.2.1.4 EEC Community Outreach

The EEC Community Outreach group was first launched in 2007, and similar to BC Hydro's PowerSmart Outreach Team, it is a grassroots channel for delivering the Companies' EEC messages. It connects with the Companies' customers through educational and interactive activities based at local community events. In 2010, the Companies attended additional events when compared to 2009 such as the Lonsdale Party on the Pier in North Vancouver, Sapperton Day in New Westminster, and several sporting events through the Vancouver Canucks and various BCHL games, and were in direct contact with at least 36,000 residential customers and the general public.

These community events generally attract a large audience as most of the events are free for the public to attend and take place in urban centres, with close proximity to residential neighbourhoods. These outreach activities have proven to be a cost-effective method of engaging a large group of the Companies' customers through a simple trivia activity and by distributing information and tools to further educate them about conservation in the home. Also, these attendees would not normally attend home shows and sporting events, so these community events allow more customers to put a "face" to the Companies and learn about energy conservation. Additional opportunities existed for the Community Outreach group to bring energy education right into several large organizations, in particular those with a staff of over 200 during lunchtime "energy fairs", as many of the employees are also residential customers. Some of the organizations visited include the City of Coquitlam, SAP Canada, and WorkSafe BC. Both the community events and the energy fairs contribute to the Companies' goal of building a culture of conservation. Refer to Appendix E for a complete list of events and organizations attended in 2010.

8.2.1.5 Employee Education

The Companies employ approximately 1,500 individuals, many of whom are themselves customers and many of whom regularly interact with customers. The goal of the Employee Education program is to create a large group of "EEC ambassadors" within the Companies who promote EEC programs and initiatives by discussing them during their dealings with the public and when interacting with their personal network.

The EEC department has traditionally communicated EEC initiatives and incentive programs to employees via the Companies' intranet and newsletters, and specific training for the call centre and field staff. In 2010, an outreach team also visited 12 office and muster locations to introduce the new EEC initiatives and programs, identify key communication channels, and identify "green ambassadors". With the rapid expansion of the EEC initiatives, it is necessary to provide the Companies' employees with continual education on all EEC programs, incentives, and local

CEO activities being implemented. In 2011, the EEC team will continue to liaise with the "green ambassadors" to inform them of new programs and initiatives.

In summary, educating residential customers and the general public on energy conservation is strongly aligned with the CEO program area's goal of building a culture of conservation in BC and it is vital to promote the related programs and initiatives through a variety of communication methods including print, interactive, and face-to-face.

8.2.2 COMMERCIAL CUSTOMERS

It is imperative that the Companies provide energy saving information to commercial customers, as they have a great potential to reduce their energy consumption. This section outlines how CEO programs educate commercial customers on conservation behaviours. It is the Companies' view that providing education on behavioural changes helps commercial customers reduce their organization's energy consumption and encourages them to pursue additional efficiencies by participating in EEC incentive programs. The commercial sector is made up of small and large businesses in a variety of industries, such as retail, offices, multifamily residences, schools, hospitals, and shopping malls, to name a few.

According to the 2010 Customer Satisfaction Study conducted by TNS, the corporate image attribute of being "committed to helping customers" is an important driver of satisfaction for small and large commercial customers. Through the various EEC initiatives, the Companies will be able to meet customers' expectations by providing increased EEC education and program information to help them reduce their organization's energy costs. This may have the potential to indirectly impact future customer satisfaction studies.

It is important for the Companies to consider a variety of media communication tools and distribution channels, and it is a goal of the CEO program to reach the diverse group of businesses in the Companies' commercial sector. In this section, energy conservation education is grouped and described according to three communication channels: print and online publications, industry trade shows and association events, and corporate behaviour change pilot programs.

8.2.2.1 Print and Online

Print and online publications are a cost-effective communications channel for delivery of industry targeted information when compared to other communication channels such as television and mass media. The goal of the CEO print and online publications is to provide ongoing communication to commercial customers about the Companies' energy conservation initiatives. In 2010, the Companies continued to provide information through energy saving handouts and bill inserts for small commercial customers and various print and directory advertising such as show guides and property management directories. In addition, the CEO program area is co-funding, along with other departments in the Companies, a bill insert and bill messaging research study conducted by TNS. The purpose of this study is to determine readership levels, understand if certain messages garner more attention from readers than other messages, and the type of information desired by our customers. The primary targets for the study are residential and small commercial (i.e. Rates 2 and 3) customers who are also the key audiences for EEC programs. The research firm, TNS, are testing three waves of bill inserts through phone surveys. The study began in Q4 2010 and will be completed by Q2 2011.

8.2.2.2 Trade Shows and Association Events

Industry trade shows and association events remain an effective way to reach commercial customers by targeting key decision makers and identifying energy savings opportunities they can consider for the businesses they represent. Based on the increasing number of customer inquiries and requests for funding, the Companies strongly believe that participation in trade shows is an essential channel for educating key decision makers about available CEO educational, behavioural, and incentive programs. Participation in association events, such as the Business Improvement Association of BC's regional meetings, Rental Owners and Managers Society of BC tradeshow, and BC Hydro PowerSmart Forum, provides the Companies with an opportunity to promote CEO education and EEC incentive programs to both small businesses and large commercial customers. In 2010, the Companies attended generally the same shows as the previous year and were in direct contact with over 1,500 key decision makers. For a complete list of 2010 trade shows, please refer to Appendix E.

8.2.2.3 Behaviour Change Programs

Under the BC Climate Action Charter, several municipalities (i.e. the Companies' commercial customers) have committed to becoming carbon neutral by 2012. In their dealings with some commercial, institutional, and municipal customers, the Companies have received anecdotal indications that since these customers are strapped for financial resources, they have to focus on low cost behaviour adjustments in their efforts to reduce energy costs within their facilities. As a result, the Companies are currently piloting behaviour change programs for commercial and municipal customers, due in large part to customer demand. The goal of the behaviour change pilot programs is to develop a successful program design and then expand to other large commercial and public organizations. Behavioural changes are currently not incorporated into the Companies' savings portfolio because of the difficulty tracking results from individual actions; however, in the two pilot programs described below, they have both included a benchmark in an attempt to measure any changes in behaviour.

Behaviour change programs, also known as community based social marketing, look to identify the barriers to behaviour change, design a strategy utilizing behaviour change tools, and then implement that strategy. The benefits of implementing a behaviour change program include understanding the psychological and motivational aspects of human behaviour in decision-making, and the power of community and peer influence to develop an engagement strategy that may have a longer-lasting impact than traditional mass media campaigns. Another foundational element of behaviour change is that people tend to adjust their behaviours so as to create consistency through all aspects of their lifestyle. For instance, an individual who learns through CEO programs to conserve energy at work is plausibly more likely to transfer those energy saving behaviours to the home (or vice versa). Below is a description of two behaviour pilot programs that began in 2010: Destination Conservation for Public Buildings and Health Authority Staff Engagement.

8.2.2.3.1 Destination Conservation for Public Buildings Pilot Program

In 2010, a behaviour change pilot program was launched to a group of five South Okanagan organizations: the Regional District Okanagan Similkameen, City of Penticton, District of Summerland, Town of Oliver, and Okanagan College Penticton Campus. The goal of the one year pilot program is to test the program with public buildings. If energy savings reductions are achieved through benchmarking and tracking surveys, the Companies will provide this program as an additional EEC service offering to other municipalities and public organizations. MVS Consulting will first work with various municipal staff, such as senior administration, facilities, community outreach coordinators, and other peer leaders, to perform energy audits of the facilities for benchmarking purposes. Second, MVS Consulting will develop an employee engagement strategy to determine if both low cost/no cost efficiency improvements and behavioural changes from staff will bring about energy reductions in municipal office facilities. The Companies co-funded the program with FortisBC Inc.

8.2.2.3.2 Health Authority Staff Engagement Pilot Program

The development of an online community site for health authority employees that promotes energy conservation actions for work and home began in 2010. The goal of this initiative is to pilot an online community site and develop an extensive employee engagement strategy that can eventually be implemented by other health authorities and/or large institutional customers. With this tool, the Companies hope to investigate the attribution of energy savings to this behavioural program thus potentially providing a benchmark for capturing energy savings from other education and outreach activities.

The target audience for this program began with the Vancouver Coastal Health Authority and Providence Health Care with a combined total of approximately 28,000 employees; however, it has now been extended to include Fraser Health Authority, Providence Health Care, and Provincial Health Services Authority, which could bring on an additional audience of 32,000 full time employees, part-time employees, volunteers, and contracted employees. The program for the four health authorities is set to launch in March 2011. As the Companies have minimal experience in developing a large scale employee engagement program, an external consultant, Resilient Group, has been hired to build capacity and knowledge within the EEC group about social marketing and its role in large-scale employee engagement initiatives. Much of the costs of the program, in particular the site development and engagement plan are one-time costs. The ongoing marketing campaigns will encourage participants to learn about energy conservation, make social commitments towards behavioural changes, and take action to reduce GHG emissions at work and in the home.

By providing education to commercial customers, these pilot programs are aligned with the CEO program area's goal of building a culture of conservation in BC. Behaviour change programs are difficult to measure through traditional economic tests; however, it is vital to include them and devise a benchmarking method in the CEO program area as a result of customer demand.

8.2.3 CONSERVATION FOR AFFORDABLE HOUSING

As indicated in the EEC Decision, the Companies were directed to review the CEO program area with a view to "altering the program to allocate funds away from the mass media campaign, and to include other initiatives, with particular attention paid to... affordable housing initiatives." With approximately 20 percent of the Companies' customers coming from the low income sector, support within the CEO program area for the Conservation for Affordable Housing program started developing in late 2010. The Companies supported the first BC Housing Affordability Symposium with funding. Education, including print and online advertising, ethnic material development, and outreach and engagement efforts, will be further developed in 2011 to complement the initiatives in the Conservation for Affordable Housing program area.

8.2.4 SCHOOL OUTREACH

The EEC portfolio is aligned with section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), a public utility's plan portfolio is adequate only if it includes an education program for students enrolled in schools in the Companies' service area. This section outlines how the CEO program area supported various school programs in 2010. It is the Companies' view that funding multi-year school programs will build a strong foundation for a culture of conservation in BC through consistent curricula. The goal of the Companies' school outreach activities is to educate K-12 students on natural gas and how gas fits into the province's energy picture as a first step in informing students about energy conservation. By reaching out to students, the Companies are instilling conservation knowledge early in the life of our future customers. As school programs generally run over the September to June time period, some programs in 2010 started the year previous, while others are continuing into 2011.

Table 8-5 summarizes the school programs that the Companies are currently supporting:

Table 8-5: Summary of School Programs, 2009-2010 and 2010-2011 School Years

School Program	School Year
BC Green Games	2009-2010 and 2010-2011
BC Lions Energy Champion School Assembly Presentations	2009-2010 and 2010-2011
Beyond Recycling	2009-2010 and 2010-2011
Destination Conservation	2009-2010 and 2010-2011

Below describes in detail the four school programs that address the regulation and were directed to elementary and secondary students: BC Green Games, BC Lions Energy Champion School Assembly Presentations, Beyond Recycling, and Destination Conservation.

8.2.4.1 BC Green Games

BC Green Games is a province-wide competition hosted by Science World. The Companies have been co-sponsoring this initiative with BC Hydro since the 2009-2010 school year. By co-sponsoring this initiative, the Companies are able to introduce the concept of natural gas as a resource and the need for energy conservation into the environmental projects developed by students. The Green Games competition requires student teams to submit digital entries of their environmental projects for prizes.

BC Green Games ties into other initiatives such as Destination Conservation and Beyond Recycling by providing a means to showcase team projects that were developed in those programs. Where Destination Conservation and Beyond Recycling successes have been limited to the school or community, BC Green Games provides the social network channel to allow students to learn about initiatives in other schools, learn from their peers, and build on their existing, or new, projects for the next school year.

The 2009-2010 school year saw 94 submissions to the BC Green Games competition from 32 school districts across the province; furthermore, 3,981 votes were cast and over 24,400 website visitors were reached between August 31, 2009 and April 15, 2010. For the 2010-2011 school year, new goals have been set to increase the profile of the BC Green Games across the province, as well as increase the number of energy related projects (20 percent of the total amount) that are submitted. These goals will be achieved through a communication strategy that emphasizes the simplicity of the contest and focuses on strengthening the relationship with local school district champions and mentors. BC Green Games will provide the Companies with a full report at the completion of the competition, including, but not limited to: number of submissions, number and location of schools involved, types of projects, and web analytics.

8.2.4.2 BC Lions Energy Champion School Assembly Presentations

Since the 2008-2009 school year, the Companies have partnered with the BC Lions school program division to deliver interactive and informative presentations on energy and water conservation to elementary schools throughout BC. The goal of this initiative is to develop a program that interacts with students and brings conservation education directly into the schools.

In the 2009-2010 school year, presentations were delivered to 75 elementary schools, successfully reaching over 21,000 students, which is an increase from 50 schools and approximately 14,000 students reached the previous year. Partnering with the BC Lions has been beneficial as the players act as role models in promoting energy conservation and teamwork. Post-presentation surveys with the principals have all shown fairly strong satisfaction with the presentation, players, and props.

The Companies are a title sponsor of the program, with minimal funding provided from Plutonic Power for the 2009-2010 school year. The Companies and BC Lions will continue to partner and deliver this program in the 2010-2011 school year. Refer to Appendix E for a list of the schools that received the presentations.

To summarize the Companies' school outreach initiatives, multi-year school programs have proven beneficial for both teachers and program planners to plan consistent curricula, as well as for students who can work with peers to build on previous project successes; therefore, the CEO program area will continue to fund and expand on the number of initiatives for schools in 2011.

8.2.4.3 Beyond Recycling

The Beyond Recycling program is delivered by Wildsight, a non-profit organization that focuses on biodiversity and healthy human communities in the Columbia region. Beyond Recycling provides students with an understanding of the connection between consumption patterns and environmental impacts. The goal of the Companies' funding of this program is to ensure conservation outreach to schools that may not have otherwise been able to participate in the program.

The program contains lessons in reducing waste and GHG emissions, and the role of natural gas in BC. The lessons also include actions such as students performing home energy audits and conservation pledges. The Companies co-fund the program with Environment Canada's EcoAction Community Funding Program and FortisBC Inc. Feedback on the program has been collected from teachers, students, and program educators and has been incorporated into the 2010-2011 curricula to improve the program. Refer to Appendix E for a list of participating schools in the 2009-2010 and 2010-2011 school years.

8.2.4.4 Destination Conservation

The Pacific Resource Conservation Society's Destination Conservation ("DC") program is a three-year K-12 school program involving students, teachers, and school facilities management staff. The main purpose of the program is to educate schools on ways to reduce the consumption of energy and water and the creation of waste, and motivate schools to participate in energy conservation projects. The Companies' support of a multi-year school program provides stability in planning for teachers and students, allowing them to build upon previous lessons and projects. Feedback has been collected on the program from teachers, students, and program educators and has been incorporated into the 2010-2011 curricula to improve the program. Refer to Appendix E for a list of participating schools in the 2009-2010 and 2010-2011 school years.

8.2.5 SUMMARY OF 2010 CEO INITIATIVES

The CEO initiatives follow many of the same program principles that were put forth in the EEC application. These initiatives are designed to be accessible to all customers, uniformly across FEI and FEVI territories, and are multi-year programs to ensure effective implementation and stability in the marketplace. The objective of CEO initiatives is to support the development of a culture of conservation within British Columbia.

All of the initiatives described throughout this section are continuing into 2011, and are vital in promoting and educating the public on energy conservation behaviours and keeping the Companies' conservation message "top of mind" among customers. The result will be fostering a culture of conservation, which will benefit communities, increase participation in EEC incentive programs, and ultimately support shared goals of the Companies and province.

8.3 2011 CEO Programs and Initiatives

All of the initiatives described in the previous section are continuing into 2011 in the proposed budget shown in Table 8-6, as they have proven to be vital in promoting and educating the public on energy conservation behaviours and in fostering a culture of conservation.

Table 8-6: Summary of CEO 2011 Proposed Budget

	Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
CEO Portfolio Administration	$100	$38	$138	N/A	N/A	N/A	N/A	N/A
Residential and General Public Education and Outreach	$1,500	$275	$1,775	N/A	N/A	N/A	N/A	N/A
Commercial Customers Education and Outreach	$700	$200	$900	N/A	N/A	N/A	N/A	N/A
Conservation for Affordable Housing Education and Outreach	$200	$55	$255	N/A	N/A	N/A	N/A	N/A
School Outreach	$390	$80	$470	N/A	N/A	N/A	N/A	N/A
Total	$2,890	$648	$3,538	N/A	N/A	N/A	N/A	N/A

However, as the CEO program area is still developing, there are several new projects to develop and launch among the different customer groups. This section describes the new, or expanded, opportunities in 2011 such as ethnic outreach, community outreach expansion, home efficiency measures partnerships, Pacific National Exhibition prize home showcase, construction and real estate industry education, education seminars for small businesses, conservation for affordable housing outreach, and post secondary programs.

8.3.1 RESIDENTIAL AND GENERAL PUBLIC EDUCATION

8.3.1.1 Long Term and Event Tracking Research Studies

As indicated in Section 8.2.1, the various EEC initiatives have the potential to raise the Companies' level of customer satisfaction by meeting customers' expectations of keeping energy costs within their budget. In 2011, the CEO program area is developing two research studies for long term tracking and event tracking. The purpose of the Long Term Tracking Study is to track awareness levels for EEC messaging and programs over time among the general public and ethnic audiences, as well as to measure message retention and determine which campaigns/initiatives are most effective at reaching broad audiences. The study will also provide recommendations on opportunities to increase awareness of EEC initiatives. The purpose of the Event Tracking Study is to determine the success of the overall approach (event attendance and/or sports team partnerships along with an online contest) for raising awareness about energy conservation. This study will help the CEO program area ensure effective event and sponsorship selection, as well as indicate how the Companies can increase participation, awareness, and conservation while building positive brand recognition when developing future programs and initiatives. The studies will begin in Q2 2011.

8.3.1.2 Ethnic Outreach

British Columbia is a culturally diverse province, and a successful EEC portfolio will be aware of the unique needs of ethnic groups. The ethnic marketing and communications outreach campaign that began development in 2010 will grow further in 2011. To ensure conservation education is accessible to all customers, the Companies will create print and online materials for ethnic markets and develop partnerships with third party service providers for distribution and promotional channels. New Canadians – primarily coming from China (23 percent), India, the Philippines and South Korea[40] – are a main source of population growth and housing demand in British Columbia. Within six months of arrival, 17 percent of new immigrants in the Metro Vancouver region are homeowners, while more than half are homeowners after four years. Statistics show that 17 percent of British Columbians do not speak English in their homes as a primary language and approximately 27 percent have knowledge of a mother tongue other than English[41]. Thus, it is important to communicate conservation information that is relevant and easily understood by these ethnic audiences.

8.3.1.3 Community Outreach Expansion

As described in Section 8.2.1.4, most community events are free to the public and are a cost effective method for the Companies to reach out to a large number of customers. In 2011, the goal for the Outreach Team is to increase the number of events attended in the service territories of FEI and FEVI and expand the geographic scope of events attended beyond the Lower Mainland.

8.3.1.4 Home Efficiency Measures Partnerships

As discussed in Section 3 Residential Energy Efficiency Programs, the CPR has identified some efficient, low-cost fixtures that homeowners can easily take advantage of in order to achieve energy savings. One of the 2011 goals for the CEO program area is to identify outreach opportunities for delivering a program to residential and multifamily customers that allows them to learn about and take advantage of these energy savings measures. There may be the potential to leverage opportunities for program dissemination through property management associations and students in secondary and post secondary schools, and partnerships with municipalities (i.e. the District of Saanich pilot program) and big box retailers (i.e. the Sears audit program).

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[40] http://www.cmhc-schl.gc.ca/odpub/pdf/65319.pdf?fr=1296674608594
[41] http://www.bcstats.gov.bc.ca/data/cen06/facts/cff0604.pdf

8.3.1.4.1 *District of Saanich Low Flow Water and Weatherization Pilot Program*

This program is an opportunity to partner with the District of Saanich and the Capital Regional District in delivering a low flow water and weatherization pilot program for residential customers that are hooked up to natural gas. The goal of this program is to pilot direct installations of low flow showerheads, kitchen faucet aerators, and bathroom faucet aerators in partnership with a municipality and/or the regional district to promote both hot and municipal water savings and energy savings. If successful, the program will be extended to other municipalities. City Green is the service provider and will be administering, marketing, and delivering the program to the residents of Saanich, as well as reporting on the resulting energy savings. City Green will also be liaising with other municipalities to gauge interest in the program and has already been in discussions with Abbotsford, Qualicum Beach, Chilliwack, and Coquitlam.

8.3.1.4.2 *Sears Home Energy Tune-up Pilot Program*

An opportunity exists with Sears Canada and BC Hydro to pilot a program on a modified home energy audit, product change-out, and consumer education for approximately 500 homes in the Lower Mainland. The goal of this program will be to determine if a simplified home energy evaluation can be used as an effective starting point to encourage the adoption of further and more advanced energy efficiency upgrades and participation in other energy efficiency programs. Partnering with a province-wide big box retailer is also a great opportunity to utilize their communication and distribution channels to reach out to the Companies' customers. Sears will be the service provider for signing up customers, administering, delivering, and reporting on the program. The in-home tune-up will document the statistics of the home, including the approximate efficiency of the appliances, and will include the installation of basic energy saving products such as: low flow faucet aerators, low flow showerheads, pipe insulation, compact fluorescent light bulbs, and electrical power bars. If this program is successful, it can be delivered to other communities within the Companies' service territories.

8.3.1.5 Pacific National Exhibition Prize Home Showcase

An opportunity exists with the Pacific National Exhibition Prize Home at the 17 day summer fair in Vancouver to showcase and provide education regarding high efficient equipment and conservation to the 100,000+ attendees from the Lower Mainland that walk through the prize home annually. The opportunity includes on and off-site presence such as; website promotion, print advertising in newspapers and show guides, signage with efficiency ratings within the prize home, and an onsite presence with the Outreach Team interacting with the attendees.

8.3.1.6 New Construction and Real Estate Industry

As discussed in Section 3 Residential Energy Efficiency Programs, the residential new construction industry is a key influencer group to educate on EEC messages since the installation and end-use of efficient technologies go hand-in-hand. This includes education and training sessions for not only new development showroom staff and salespeople, but also the real estate and home appraisal industries on appliance efficiency ratings, the benefits of efficient natural gas appliances, and other home conservation measures such as low flow showerheads. Marketing materials such as appliance stickers with efficiency ratings, sticker reminders and homeowner packages will also be developed to educate the end user.

The Companies will also continue to support the regional CHBA branches. In 2011, the Companies entered into an agreement with CHBA BC to fund the BC Housing Affordability Symposium as a keynote presentation partner and the Second Annual Built Green™ BC Awards as co-presenter. The main goals of supporting these events are to enhance the Companies' profile in the residential construction industry and increase knowledge of the energy efficiency and conservation rebates and programs available to builders/developers and homeowners.

8.3.2 COMMERCIAL

8.3.2.1 Small Commercial Businesses Education Sessions

Small business customers represent approximately 80,000 customers in the Companies' service territories. As small businesses, they generally have limited financial resources to invest in efficient technologies; however, they are still keen on implementing energy saving measures and behaviours in their businesses. A program is in development to hold education sessions with small businesses that is expected to launch in Q3 and Q4 2011.

8.3.3 CONSERVATION FOR AFFORDABLE HOUSING

8.3.3.1 BC Housing Tenant Engagement Pilot Program

This BC Housing Tenant Engagement pilot program provides the Companies with an education and outreach opportunity to engage with BC Housing tenants in two sites in the Metro Vancouver region. The pilot program design is based on the recognition that significant energy savings can be realised through behaviour-based energy education programs aimed at reducing heat and hot water usage. BC Healthy Communities will be preparing the educational material and implementing the pilot with four main objectives: savings (energy, money, and GHG emissions), community economic development, tenant satisfaction improvement, and development of best practices.

8.3.4 SCHOOL OUTREACH

8.3.4.1 BC Sustainable Energy Association Climate Change Showdown

For the 2010-2011 school year, the Companies' entered into an agreement to support the BC Sustainable Energy Association's ("BCSEA") Climate Change Showdown program with funding. The goal of the program is to educate elementary school students and their parents about how to reducing $C0_2$ emissions and save energy in the home and at school. These free workshops will be offered to 29 schools across British Columbia starting in spring 2011. The workshops are interactive and include videos, board games, contests, and group discussions. The Companies are co-funding this program along with a number of partners including FortisBC Inc., LiveSmart BC, and BC Hydro.

8.3.4.2 Environmental Mind Grind Challenge

For the 2010-2011 school year, the Companies are supporting two Environmental Mind Grind Challenges taking place in four communities in BC, including: Kelowna (in partnership with FortisBC Inc. and the City of Kelowna), Kamloops, Penticton, and Nanaimo. The Environmental Mind Grind Challenge is a student trivia competition on energy and environmental conservation. The goal of supporting this initiative is to encourage conservation education through a fun and competitive game that allows students to interact with their peers from neighbouring schools. The Companies have supported this initiative previously and found it to be a valuable event for the students and communities involved. The competition will take place in spring 2011.

8.3.4.3 Post Secondary Program

The Companies are currently evaluating how we will move forward and expand our education and outreach activities to include greater involvement in post secondary institutions. We are in the process of reviewing proposals from vendors such as GoBeyond and looking into the possibility of hiring an external consultant to develop and implement a program on our behalf.

8.3.5 SUMMARY OF 2011 CEO INITIATIVES

Several of the CEO initiatives from 2010 will continue into 2011 because multi-year programs ensure effective implementation and stability in the marketplace. In addition, many of the programs and pilots will expand. Continuing conservation education is key to keeping the Companies' conservation message "top of mind" among customers. The result will be fostering a culture of conservation, which will benefit communities, increase participation in EEC incentive programs, and ultimately support shared goals of the Companies and the province.

9 INDUSTRIAL SECTOR PROGRAMS

9.1 Overview

Starting in late 2007 and continuing throughout 2009, BC's economy was impacted by the global financial crisis. "British Columbia's economy shrank by 2.3 percent in 2009, as the province, together with most other regions of Canada and around the world, felt the effects of the global recession"[42]. The economic recession had a negative effect on most industries, including the construction, forestry, manufacturing, pulp and paper, oil and gas, and mining sectors, resulting in an overall reduction in natural gas load from the Companies' industrial natural gas customers.

The province's large manufacturing sector includes a significant number of very large energy-intensive industrial operations such as mines, refineries, smelters, oil and gas operations, and pulp and paper mills. The industrial sector in BC is a large consumer of energy and accounts for approximately 35 to 40 percent of the total energy used in the province and roughly 38 percent of the GHG emissions generated[43]. As well, emissions reported under the industrial process category increased by 2.8 percent between 2007 and 2008[44], thus offering significant opportunities for continuous improvement to reduce and eliminate waste of all forms and especially for energy savings and GHG emissions reductions through improved energy efficiency.

9.1.1 INDUSTRIAL CUSTOMERS DEFINITION

The Companies' industrial natural gas customers have delivery service contracts with FEI that are interruptible, interruptible/firm, or firm. In a broad sense, the interruptible and interruptible/firm industrial sector are typically the largest natural gas users by volume due to large process heat applications in their facilities. These customers, which have an interruptible component to their delivery contract with FEI, have the flexibility to switch to an alternative fuel for short durations to free up pipeline capacity for firm gas customers as conditions approach design day conditions. The interruptible industry customers are offered lower delivery rates in comparison to non-interruptible, or what has been referred to as "firm" industry customers. The firm (non-interruptible) customers pay slightly higher fees for their delivery rates and the Companies do not have the flexibility to switch off their gas during peak times. In addition, some customers fall under both rate schedules. For example, some customers may prefer to be under the interruptible contract only for a certain portion of their gas consumption. Usually, they are

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[42] BC Ministry of Finance. "2010 British Columbia Financial and Economic Review 70th Edition". July 2010. Retrieved from http://www.fin.gov.bc.ca/tbs/F&Ereview10.pdf.

[43] BC Ministry of Environment. "British Columbia Greenhouse Gas Inventory Report, 2008". September 2010.Retrieved from http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2008-full-report.pdf and http://www.livesmartbc.ca/learn/emissions.html#Sector (emissions include oil & gas, pulp & paper and chemical manufacturing industries).

[44] BC Ministry of Environment. "British Columbia Greenhouse Gas Inventory Report 2008". September 2010.Retrieved from http://www.env.gov.bc.ca/cas/mitigation/ghg_inventory/pdf/pir-2008-full-report.pdf.

under firm contracts and treated as firm customers until their consumption amount goes beyond the limits provided to them. In the event these customers exceed their limits they are then considered as interruptible customers and are treated accordingly.

FEI's interruptible industry customers are usually categorized in groups of different rate schedules such as Rate Schedules 7, 22, and 27, whereas firm or non-interruptible customers are under Rate Schedules 2, 3, 5, 23, and 25. As discussed in the 2009 EEC Annual Report, FEI sought funding approval for EEC programs for interruptible industrial customers in the 2010-2011 RRA and it was approved as per Order No. G-141-09. With respect to the development of EEC programs for the manufacturing sector, the Companies had already received approval through BCUC Order No. G-36-09 for the firm industrial customers. Thus, this section of the Report will discuss both firm and interruptible industrial customers.

9.1.2 INDUSTRIAL SECTOR END USES

The major end use technologies in this sector are for steam/hot water generation for process use and direct fired drying processes. For instance, the largest energy consumption for the softwood lumber industry would result from the wood drying process in our customers' kilns. The drying kiln dries the cut lumber to selected moisture content (eight -18 percent dependent on the product and service conditions) before it is shipped offsite and sold to customers. The process is quite slow, requiring over 28 to 40 hours for spruce/pine/fir commodity products and weeks for thick and high value coastal products. Coastal products describe wood products manufactured in the coastal region of British Columbia. Areas of activity would include production of a wide range of solid wood products including high quality appearance/decorative products, structural lumber for housing and general construction, special sizes and grades for remanufacturing, as well as utility and lower grade products suitable for pallets, packaging, and other industrial uses. These products are produced in the five softwood species that grow in the coastal region: Western hemlock - Western red cedar, Yellow cedar, and Sitka spruce. The drying schedule employs temperatures in the range of 80 -105° C. Other high energy use systems for the industrial sector would include hot water and steam boilers, ovens, lime and ceramic kilns, direct fired material heaters, veneer dryers, and dryers of other products such as minerals, pulp, and paper.

9.1.3 BACKGROUND

The 2009 EEC Annual Report stated that there were three additional program areas to be introduced to market in 2010, one of these being the Interruptible Industrial program area. The intention behind interruptible industrial sector programs was to engage FEI with its interruptible industrial customers, as well as firm customers operating in British Columbia, to create energy efficiency programs, integrate energy efficiency into their ongoing business practices, and instill a conservation ethic. FEI believes there is significant potential for a reduction in industrial consumption including both firm and interruptible customers. For example, in the 2006 Conservation Potential Review, filed as Appendix 1 of the Companies' Energy Efficiency and Conservation Programs Application in 2008, it was stated that the majority of lumber dry kilns in

BC use natural gas and there are a number of upgrades possible to convert an average kiln into an energy efficient kiln. These upgrades include automatic venting, improved insulation, and heat recovery. Opportunities for improvement also exist in the chemicals, non-metallic minerals, paper, and other manufacturing sectors where boilers are used. Energy efficiency opportunities for boilers include near condensing and condensing boilers, boiler economizers, boiler combustion air-preheating, boiler condensation heat recovery, and advance boiler controls such as boiler reset controls. Thus, the Companies' Industrial Sector program area offers opportunities for energy efficiency and conservation activities for these customers, while at the same time managing the risk associated with large financial investments in energy efficiency for industrial customers and the resulting magnitude of the anticipated energy savings.

9.1.4 PROGRAM OBJECTIVES

The Companies' approved budget for 2010 and 2011 is only for FEI customers. Thus, discussion is limited to FEI. FEI's EEC programs in the industrial area are intended to provide financial incentives and tools to qualified projects to: (a) create energy-efficient plant(s) by utilizing energy efficient machinery and equipment, and (b) if the energy saving measures in the customers' new plant (facility) design involves added costs, use financial incentives to help qualified projects implement these upgrades. The industrial portfolio will help large customers to reduce their gas load and become more efficient, productive, and competitive, while also managing the risk to the Companies and ratepayers associated with large financial investments on infrastructure. In general, the EEC Industrial Sector program area is aiming to introduce initiatives and programs that seek to engage industrial customers to become more efficient in their process heating applications. Section 9.1.5 details FEI's strategy for the industrial sector.

9.1.5 INDUSTRIAL SECTOR PROGRAM AREA STRATEGY

The first step in developing the program framework for industrial programs was to create a specific strategy for the Company's firm and interruptible industrial customers. The following are determined to be the goals of the strategy:

- Identify energy management measures and develop an action plan in order to implement these measures specific to each customer. It has been observed that due to the diversity of the industrial sector in BC, no single program will meet the total needs of industry;
- Identify potential program partners (i.e. BC Hydro, Pacific Carbon Trust, Ministry of Energy and Mines and Natural Resources Canada);
- Reduce energy consumption in terms of GJs;
- Reduce environmental impacts, including GHG emissions reduction;
- Improve operational optimization and financial performance; and
- Create reliability and reduce maintenance.

After conducting research based upon other utilities' accomplishments in energy savings and GHG emissions reduction initiatives to date, as well as the use of articles published by organizations such as Natural Resources Canada ("NR Can"), Canadian Industry Program for Energy Conservation ("CIPEC"), e-Source, International Energy Agency ("IEA"), U.S. Department of Energy, internet and media news, webinars and conferences, and through meetings with counterparts from the provincial government and other utilities, significant input was garnered on the creation and development of the strategy.

As noted above, the primary objective of the Companies' industrial strategy is to identify energy management measures and to develop energy efficiency programs to optimize energy use and reduce consumption. The implementation of the strategy would include the following steps:

- Identify eligible projects through customers, engineering consultants, equipment vendor references, or through the Conservation Potential Review;
- Customer submits feasibility study, if available, or conducts an initial assessment;
- If historical natural gas consumption data is not available, the facility's manager will perform a historical analysis to determine natural gas usage patterns and performance of major natural gas equipment. In case of a situation where the customer is unable to provide data for the facility's natural gas consumption, FEI will provide this data;
- A site walk-through with the facility's energy coordinator along with FEI's industrial program manager will be completed in order to discuss natural gas savings opportunities at the site;
- If the customer does not already have one, a detailed study will be completed by an independent third party engineering firm selected/provided by the customer to determine possible opportunities for natural gas savings at the site (i.e. 'pinch technology studies' for refineries or large pulp and paper mills). The cost of the study may be partly/wholly subsidized by FEI. The basic process for obtaining the study would be as follows:
    - Applicant hires qualified engineering consultant to complete the study;
    - Engineering consultant completes the study within a reasonable time frame (i.e. 45 - 60 days);
    - The study will reflect the findings and verify their impact (i.e. verification of operational optimization such as reduced maintenance and cost/benefit analysis);
    - Applicant pays engineering consultant and obtains proof of payment;
    - Applicant submits the study and proof of payment to FEI;
    - FEI reviews and makes a decision either to approve or reject the study. In case the study is rejected, FEI will provide the reasons and at this point it is entirely up to the customer to have the study re-done if they wish to proceed; and
    - Upon approval, FEI will reimburse a certain portion of the cost of the study if:

    - The project is agreed to be implemented by the customer as a whole (i.e. partially completed projects are not eligible for any incentives); and
    - The study must promise long term savings. The amount of savings that will be revealed by the study should be greater than what is required to cover the incremental cost.
- A business case analysis for the project will be created by the Companies. The main business items that will be covered in the business case are as follows: objective and description of the project including benefits of doing the project, project outline, cost/benefit analysis, project risks, and risk mitigation strategies, along with a project budget;
- Potential program partners may be identified (i.e. BC Hydro, FortisBC Inc. Ministry of Energy and Mines and NR Can). If there is any existing potential partner, an incentive based on a cost sharing program or solution will be developed with the potential program partner;
- Senior FEI management signs off on the FEI business case;
- A preliminary legal agreement will be developed to cover off business items between the customer and FEI;
- Project roll out; and
- Ongoing project tracking and evaluation.

9.2 2010 Industrial Program Area Results

2010 was spent developing the industrial program area strategy described in Section 9.1.5 above and with site visits to customers' facilities. No industrial programs were launched in 2010; therefore, no results are presented here.

9.3 2011 Industrial Program Area Outlook

In 2011, the Companies intend to initiate a pilot program called the Pulp and Paper Industry Heat Exchanger program, as well as broaden their commitment to the energy audit funding program. Table 9-1 represents FEI's initial, high level estimate of the expenditures that will be required to support these activities for the industrial sector. It includes funding for:

- Heat exchanger pilot program and forecasted funding for other pulp mills;
- Burner management control;
- Stakeholder activity related to workshops and customer meetings; and
- A series of in-depth energy savings potential studies, or mini-CPRs, with individual customers in the food processing, manufacturing, and forest products sectors.

FEI expects the learning from programs in 2010 and 2011 will help form the basis for expanded programs in 2012 and beyond.

Table 9-1: 2011 Industrial Program Area Outlook

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Energy Audit Funding Program	$200	N/A	$200	N/A	N/A	N/A	N/A	N/A
Heat Exchanger - Pilot*	$550	N/A	$550	483,130	N/A	483,130	2.4	N/A
Heat Exchanger Pulp and Paper Mills*	$1,000	N/A	$1,000	TBD	N/A	TBD	TBD	N/A
Burner Management Contrrol*	$13	N/A	$13	6,902	N/A	6,902	4.0	N/A
Non-Program Specific Expenditures	$3	N/A	$3	TBD	N/A	TBD	TBD	N/A
Total	$1,766	N/A	$1,766	490,032	N/A	490,032	N/A	N/A

* Note: Preliminary TRC calculation. Measure life and alternative energy impact have not been verified.

9.4 Industrial Program Details

9.4.1 ACTIVE PROGRAMS

9.4.1.1 Energy Audit Funding Agreement

9.4.1.1.1 Program Overview

Energy Audit Funding Agreement	
Market	Retrofit
Audience	Industrial customers
Duration	Undefined
Incentive	Up to $20,000 per audit The program will fund up to 50% of the cost of the audits for eligible customers up to a maximum of $20,000
Partner	None
Overview	
Description	The purpose of this program is to determine if there are any opportunities in customers' industrial manufacturing processes that could help reduce the amount of natural gas used at their facilities, as well as to look for opportunities for customer projects to be pilot projects for each industrial sector. The Companies' financial support will help customers hire an engineering firm/contractor to conduct an energy efficiency audit at their facilities/plants, which will investigate specific natural gas savings opportunities. Audits will include an inventory of the equipment and related infrastructure including steam distribution networks. The current operating efficiencies, and the age and condition of the equipment will be determined. Energy audits will also include drawings, process diagrams, current energy use, and operating and

	maintenance costs, and will make recommendations on possible efficiency upgrades and/or technology replacements with a deep focus on natural gas savings opportunities. They will also contain incremental costs for implementation of the natural gas savings measures. The reports will clearly indicate the net savings amounts in terms of gigajoules per each measure identified in the audits. Should the energy saving measures uncovered in the audits involve additional costs, the eventual intention is for the Companies to provide additional financial incentives to help qualified projects implement these upgrades. Although the incentive amount is still under development, it will heavily link to the amount of savings and will vary on each project. The greater the amount of savings, the greater the incentives will be. The Companies believe the industrial energy audit funding program will deliver value by encouraging industrial customers to implement the measures that will be disclosed as a result of these audits. There has been strong customer interest in our industrial program energy audits that are used to determine the potential energy savings opportunities in the industrial sector.
Goals	• Support customers with financial incentives to hire an engineering firm/contractor to conduct an energy efficiency audit at their facilities/plants. • Uncover any existing natural gas savings opportunities within these facilities. • Identify energy efficiency pilot project opportunities for further advancement that may be applicable to BC's industrial sector as a whole. Determine the current operating efficiencies, age, and condition of the equipment/machinery at different facilities in terms of energy efficiency and upgrade this machinery.
Status	Active
Implementation	
Administration	The Companies' EEC industrial programs staff
Communications	One-on-one by the EEC industrial program manager and the Companies' industrial account management staff
Evaluation Strategy	The evaluation of the program will be based on the customers' implementation of the savings measures uncovered through the audits, and the amount of energy savings that result from the implementation of those measures.

9.4.1.1.2 2011 Program Performance Forecast

In 2011, the industrial program area has committed to providing incentives for an energy audit funding program. As discussed above in the strategy section, a detailed study will be completed by an independent third party engineering firm/contractor selected/provided by the customer to determine possible opportunities for natural gas savings at their site. The key objective for this initiative is to support industrial customers in conducting energy studies. The incentives are geared to uncover energy savings opportunities within industrial processes to reduce natural gas usage and lower GHG emissions. The Companies believe the industrial energy audit funding program will deliver value by encouraging industrial customers to implement the measures that will be transparent as a result of these audits.

Table 9-2: 2011 Energy Audit Funding Performance Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	10	$200	$3	N/A	N/A	N/A	N/A
FEVI	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	10	$200	$3	N/A	N/A	N/A	N/A

9.4.2 PROGRAMS IN DEVELOPMENT

9.4.2.1 Heat Exchanger Program - PILOT

The Industrial Sector program area is currently working on potential funding opportunities for a pilot referred to as the Pulp and Paper Industry Heat Exchanger (“HEX”) pilot program. The key objective for this pilot is to replace pulp and paper industry customers’ outdated heat exchangers with new energy efficient ones. In the pulp and paper industry, natural gas is extensively used for pulp drying and there are about 32 pulp and paper mills in BC. Gas savings will come from the heat exchanger process running hotter water, which means the final pulp stock in a liquid form will enter the mechanical dewatering process at a higher temperature. This makes the presses perform better so the pulp will contain less water when it enters the flash drying stage after the dewatering presses. Initial estimates of natural gas savings for this specific upgrade are estimated to be around 70,000 GJ/yr. If the pilot is successful, one of the other key objectives for this program will be to support the pulp and paper industry with new efficient heat exchangers. The potential uptake for all the pulp mills in BC, just for the heat exchangers, could yield savings of 1,500,000 GJ/yr. The scope and measurement and evaluation strategy for this pilot are currently being established. The following table provides the performance forecast for this pilot.

Table 9-3: HEX Program (Pilot) Performance Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI*	1	$500	$50	70,000	483,130	N/A	2.4
FEVI	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	1	$500	$50	N/A	N/A	N/A	2.4

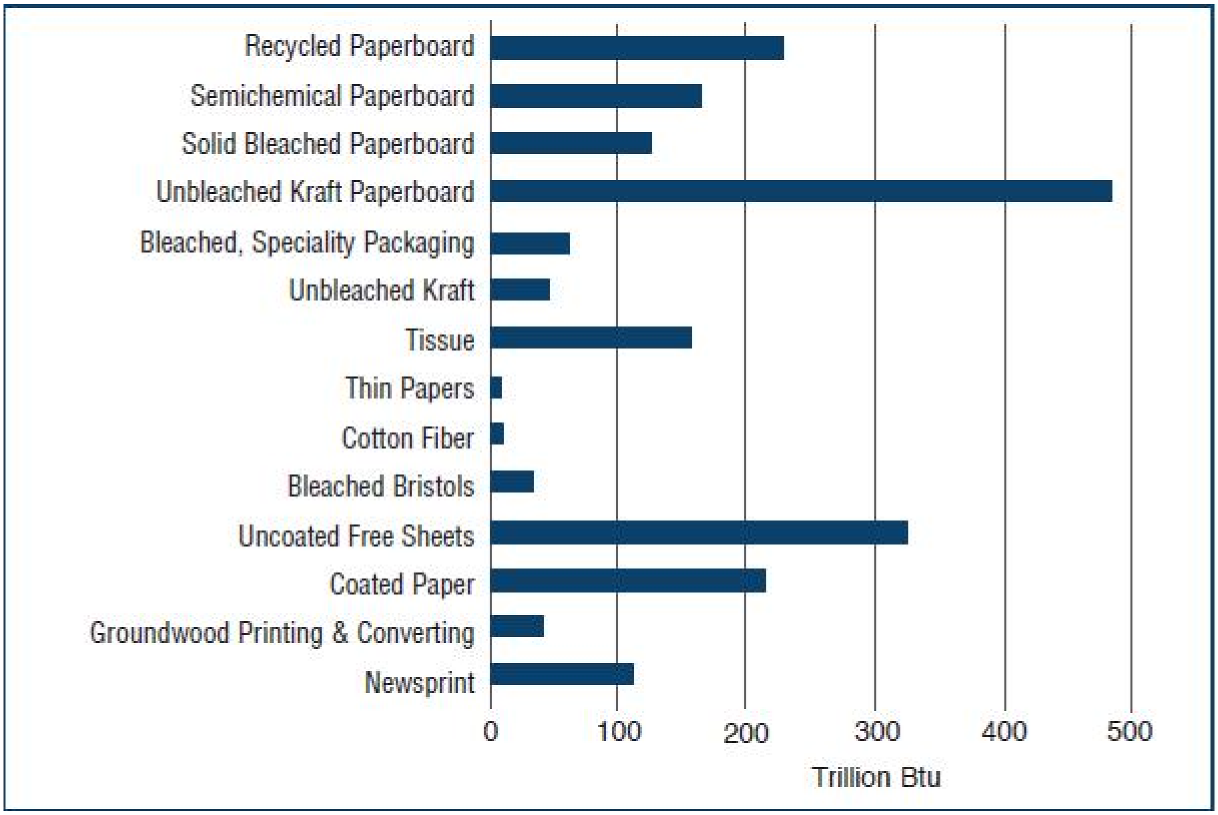
* Note: Preliminary TRC calculation. Measure life and alternative energy impact have not been verified.

9.4.3 FUTURE INDUSTRIAL PROGRAM OPPORTUNITIES

It should be noted that key industrial EEC opportunities exist in the area of waste heat. Waste heat, in the form of hot gases or fluids, is the primary source of losses from fluid heating and boiling. Fluid heating and boiling is a critical component of many of the most energy intensive processes used in the manufacture of chemicals, refined petroleum products, food and beverage, and mining and forest products including the pulp and paper industry. The energy systems utilized for fluid heating and boiling include fired systems such as furnaces, evaporators, dryers, condensers, and other direct-fuelled systems and steam generators, mostly boilers. The auxiliary equipment used to transfer and deliver steam and heat, such as heat exchangers and steam injectors, is also an integral component of industrial energy systems; therefore, the projected industry energy efficiency programs will focus both on these energy systems and on the auxiliary equipment utilized in the industry. The intelligence acquired from the pilot heat exchanger program described in Section 9.4.2.1 above would apply to other sectors where fluid heating and boiling is crucial in the customers' process.

In pulp and paper manufacturing, waste steam, hot water, and evaporation of spent liquors are the primary source of energy loss from fluid heating and drying. The two most energy intensive processes are paper drying and black liquor concentration (both being evaporation processes). The processes contributing the most energy loss are paper drying, evaporation, pulping, chemical recovery, and bleaching. These processes are heavily dependent upon steam as an energy source. For example, the Table 9-4 below shows the amount of steam energy used at different stages for a pulp and paper industry when producing different products.

Table 9-4: Estimated Steam Energy Use for Major Pulp and Paper Products[45]



In the food processing industry, significant energy is lost from fluid heating and boiling. Most of the waste energy is in the form of waste steam, exhaust gases, and radiative heat losses from evaporators, dryers, and other key processes.

In metal melting and heating, the primary sources of energy loss in fired systems are hot gases (both contaminated and clean), warm water, and hot products that must be cooled or quenched. In iron and steel making, for example, energy is lost when hot products such as coke, molten iron, hot slabs, and process gases are cooled. Smelting, which produces molten metal, generates energy losses in the form of furnace exit gases. Major sources of energy loss from calcining processes are exhaust gases such as evaporated water, combustion gases, and carbon dioxide from calcinations.

During process heating, the energy is mainly lost as waste gases from boilers and due to fouling that impedes heat transfer. The energy lost due to these inefficiencies must be supplied by burning additional natural gas or other types of fuels. Opportunities for improvement exist in the chemicals, non-metallic minerals, paper, and other manufacturing sectors where boilers are

[45] A Report prepared by Resource Dynamic Corporation for the U.S. Department of Energy. "Steam System Opportunity Assessment for the Pulp and Paper, Chemical Manufacturing, and Petroleum Refining Industries". October 2009. Retrieved from http://www1.eere.energy.gov/industry/bestpractices/pdfs/steam_assess_mainreport.pdf.

used. Energy efficiency opportunities for boilers include near condensing and condensing boilers, boiler economizers (with condensing economizers, the overall boiler efficiencies can exceed 90 percent), boiler combustion air-preheating, boiler condensation heat recovery, and advance boiler controls such as boiler reset controls. For example, the automatic control of excess air (oxygen trim) increases the boiler efficiency by one to two percent. A general rule accepted by the industry is that a one percent reduction in excess oxygen will reduce fuel usage by one percent. For very large boilers, efficiency gains of 0.1 percent mean significant annual savings and these controls usually measure carbon monoxide as well. Even with well-adjusted burners providing the minimum flue gas temperatures while achieving complete fuel combustion, there is ample room to recover some of this heat that would otherwise “go up the stack”. Heat exchangers can be used for preheating boiler feed water or combustion air. A 20° C (36° F) reduction in flue gas temperature will improve boiler efficiency by about one percent. The following cross-industry technology matrix provides a summary of savings opportunities vs. for each different industry. Blue shading indicates an opportunity available in that industry. One of the key objectives for the Industrial Sector program area is to focus on these opportunities when developing energy efficiency and conservation programs.

Table 9-5: Matrix Diagram Showing Savings Opportunities for Each Different Industry[46]

	Waste heat recovery/ gases and liquids/ chemicals, petroleum, forest products	Combined heat and power	Advanced industrial boilers	Heat recovery from drying	Steam best practices	Pumped system optimization	Energy system integration	Improved process heating/ heat transfer/ chemicals, petroleum	Efficient motors/ rewind practices	Waste heat recovery/ gases/ metals and minerals.	Energy source flexibility	Improved sensors, controls	Improved process heating/ heat transfer/ metals melting, heating	Compressed air optimization	Optimized materials processing	Energy recovery/ by product gas	Energyexport and co-location	Waste heat recovery/ calcining	Heat recovery/ metal quenching/ cooling	Advanced process cooling/ refrideration
Petroleum Refining	■	■	■		■	■	■	■	■		■	■		■	■	■	■			■
Chemicals	■	■	■	■	■	■	■	■	■		■	■		■	■	■	■			■
Forest Products	■	■	■	■	■	■	■	■	■		■	■		■	■	■	■	■		
Iron and Steel		■	■		■	■	■		■	■	■	■	■		■	■	■		■	
Food and Beverage	■	■	■	■	■	■	■	■	■		■	■		■	■		■			■
Cement				■		■	■		■		■	■			■			■		
Heavy machinery		■	■		■	■	■		■		■	■	■				■		■	
Mining						■	■		■		■	■			■				■	
Textiles	■	■	■		■	■	■	■	■		■	■		■			■			
Transportation Equipment		■	■		■	■	■		■		■	■	■				■		■	
Aluminum & Alumina						■	■		■	■	■	■	■		■				■	
Foundries						■	■		■	■	■	■	■		■				■	
Plastic and rubbers	■	■	■		■	■	■	■	■		■	■		■			■			
Glass and Glass products						■	■		■	■	■	■	■		■					
Fabricated Materials						■	■		■	■	■	■	■						■	
Computers, electronics, appliances						■	■		■		■	■								

9.5 Summary

The Industrial Sector program area represents a crucial component of the Companies' overall commitment to EEC activities. Since being staffed with a program manager at the end of Q2 2010, the industrial program area has initiated its own strategy and established relationships with key industry stakeholders. An Energy Audit Funding Agreement program has also been initiated in order to provide customers with financial contributions for conducting energy studies intended to uncover energy saving measures customers could implement.

In 2011, the Industrial Sector program area will focus on developing programs for those customers (both firm and interruptible) where fluid heating and boiling is being used as an energy intensive process in the manufacture of pulp and paper products, chemicals, refined petroleum products, food and beverage, and forest products. The Companies believe these customers offer opportunities for energy efficiency and conservation.

[46] Technology Roadmap: "Energy Loss Reduction and Recovery in Industrial Energy Systems". November 2004.

10 INNOVATIVE TECHNOLOGIES PROGRAM AREA

The Innovative Technologies Program Area overview is divided into two parts. Part 1 reports on 2010 and 2011 programs within the Innovative Technologies Program Area as a whole, while Part 2 specifically addresses the use of EEC funds for Natural Gas Vehicle ("NGV") reimbursements.

10.1 2010 and 2011 Programs

10.1.1 INTRODUCTION

10.1.1.1 Definition

Innovative technologies are best described as market ready technologies that have little or no market penetration in BC. They can be defined as emerging and/or enabling technologies. Some of these technologies include, but are not limited to, solar thermal domestic hot water systems, solar air systems, ground source heat pumps ("GSHPs"), hydronic systems, sterling engines, micro co-generation, NGVs, and fuel cells. Hydronic systems can be classified as enabling technologies as they have the flexibility and potential to receive future energy from District Energy Systems ("DES"). Innovative technologies are solutions the Companies can support through programs delivering energy reductions and savings to their customers for now and into the future. All programs within this program area are to "foster and further the deployment of forward-looking low carbon technologies."[47] The non-NGV programs within the Innovative Technologies Program Area attempt to achieve this objective by encouraging residential, commercial, and industrial customers to reduce their overall consumption of natural gas, while the NGV programs within the Innovative Technologies Program Area encourage the adoption of NGVs. The use of NGV engines, which run on liquefied natural gas ("LNG") or compressed natural gas ("CNG") as a heavy duty vehicle fuel are considered part of the Innovative Technologies Program Area for two reasons. First, technologies used in NGV applications can be classified as emerging technologies in the BC context as they have minimal market penetration in BC. Second, the Commercial NGV Demonstration program (described as "NGV for Commercial Vehicles" in the 2009 EEC Annual Report) achieves GHG emissions reductions by displacing high-carbon diesel fuel.

The Companies' target market for CNG includes operators of commercial, return-to-base heavy duty fleet vehicles such as garbage trucks, waste haulers, and buses, while the LNG focus is on long-haul, return-to-base fleet vehicles such as Class 8 tractors. In both cases, the alternative fuel source is diesel, which is a higher carbon fuel.

[47] EEC Application, at page 69.

Innovative technologies programs, including the Commercial NGV Demonstration program, are to be run as pilots and/or demonstration projects that would subsequently provide data to enable the Companies to establish the appropriate timelines, key milestones, and completion dates for full-scale program activity in the innovative technologies area.

10.1.1.2 Background

On April 16, 2009, the Commission issued the EEC Decision approving funding for FEI and FEVI for 2009 and 2010 programs. While the Companies did not receive approval for expenditures for the Innovative Technologies Program Area as part of that application, the Commission directed the Companies to bring forward projects for consideration as they became more fully developed.[48]

FEI and FEVI submitted their respective applications for 2010 – 2011 Revenue Requirements and Delivery Rates on June 15, 2009 and June 29, 2009, respectively, which proposed innovative technologies programs and expenditures in order to meet the Commission's directives in Order No. G-36-09. On November 26, 2009, the Commission issued Order No. G-141-09, approving the Negotiated Settlement Agreement ("NSA") for FEI. This EEC budget that was approved as part of that NSA included the requested FEI innovative technologies program budget of $2.334 million in 2010 and $4.669 million for 2011, for a total budget of $7.003 million.[49] FEVI's NSA, which was also approved, included an EEC envelope that encompassed the requested $478,000 in 2010 and $956,000 for 2011, for a total FEVI budget of $1.435 million.[50]

As part of their respective NSAs, the parties explicitly agreed that the Innovative Technologies Program Area will be managed by FEI and FEVI as a separate segment of the overall EEC portfolio and have a weighted total resource cost ("TRC") of 1.0 or more. FEI's NSA provided as follows in this regard, with FEVI's NSA being identical but for the name of the company and dollar amounts.

Item 12.1 of the FEI's NSA states:

> *"(d) <u>EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application.</u>*

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[48] EEC Decision, at page 41.

[49] The FEI NSA provides in section 11(c): "EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application," and in section 12.1(d): "EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application."

[50] The FEVI NSA provides in section 6(b): "EEC funding for innovative technologies will be $0.478 million for 2010, which is the amount requested by TGVI in the Application," and section 7.1(c): "EEC funding for innovative technologies will be $0.956 million for 2011, which is the amount requested by TGVI in the Application."

(e) All agreed to EEC expenditures will be considered and evaluated within the existing EEC portfolio, and will be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6).

However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(f) TGI will report to the Commission on industrial interruptible and innovative technology programs as part of TGI's annual report on EEC activities required under the EEC Decision." [Emphasis added.]

10.1.1.3 Innovative Technologies Program Area Incentives

10.1.1.3.1 Level of Incentives

It is too soon for the Companies to be able to determine the appropriate level of financial incentives necessary to make innovative technologies in general attractive to customers in the long-term; thus, there is a need to conduct pilot programs and demonstration projects to test the effect differing levels of incentives have on adoption rates, such as the pilot programs currently underway for the solar thermal residential pilot. NGV programs necessitate incentive funding due to the high upfront capital cost of NGVs versus conventional fuelled vehicles. At present, original equipment manufacturer ("OEM") CNG vehicles command a price premium of 20 – 30 percent over their conventionally fueled equivalents. The price premium of LNG vehicles ranges from 50 – 65 percent. In the case of the Commercial NGV Demonstration program, which provides an incentive of up to 100 percent of the incremental capital cost for heavy duty vehicles, there have already been contractual commitments from customers. This demonstrates there is a strong correlation between the level of incentives and adoption for NGVs. The use of EEC Innovative Technologies funding for the Commercial NGV Demonstration program is discussed in Part 2 below. In general, the Companies believe the required level of incentives can be expected to decline as the innovative technologies gain a greater share of the market, but determining exact values and timing is challenging at this time because predicting market share for emerging technologies can be difficult and subjective.

10.1.1.4 Funding Transfers

As described in Section 2 of the Report, the Companies identify the transfer of funds from one program area to another. The transfer involves funding from the Conventional EEC Program Area to the Innovative Technologies Program Area in the amount of $3.487 million. In compliance with requirements set forth in Order G-36-09, the transfer amount, the rationale supporting the transfer, and the impact of the transfer are described below.

10.1.1.4.1 Funding Amount

In the 2010-2011 Revenue Requirements Application NSA, FEI received approval for EEC funding of $2.334 million in 2010 for the Innovative Technologies Program Area. While FEI was under spent in the Conventional EEC Portfolio compared to approved levels, there was more invested in innovative technologies in FEI than was identified in the Revenue Requirements Application. For FEI, actual expenditures in 2010 were approximately $5.821 million, and approximately $3.487 million was transferred from the Conventional EEC Program Area to the Innovative Technologies Program Area.

10.1.1.4.2 Rationale

The two rationales that support the reallocating of funding are: (1) reaching a favourable TRC score for the Innovative Technologies Program Area; and (2) obtaining GHG emissions reduction benefits associated with switching the transport industry from higher carbon fuel sources.

1. The TRC score for the Innovative Technologies Program Area has met the TRC threshold of 1.0 or greater.

The Innovative Technologies Program Area has a weighted average TRC score of 1.2. Without the transfer of funds, the programs within the program area would have not been able to reach the participant levels cited in the Report.

The TRC test "is the ratio of discounted total program benefits to discounted total program costs over a specified period of time. A benefit-cost ratio greater than one indicates the program is beneficial, on the basis of the TRC test."[51] The TRC test does not consider societal benefits - which can be defined as "effects of externalities, such as environmental implications" – such as GHG emissions reductions benefits or positive impacts on delivery rates for existing customers as a result of load building facilitated by the EEC funding. As the Commission stated in the EEC Decision,

> *"While recognizing that societal factors have significance, the Commission Panel views many of these factors as being rather subjective and difficult to measure. …The Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such."*[52]

Although GHG emissions reductions are not considered as part of the TRC test, one of the objectives of the Innovative Technologies Program Area is to reduce GHG emissions, making its GHG emissions reductions important in context of the overall evaluation.

[51] EEC Decision, at page 34.
[52] EEC Decision, at page 33.

2. The Innovative Technologies Program Area promotes fuel switching from a higher carbon fuel (diesel) to a lower carbon fuel (natural gas).

The Companies believe the EEC expenditures in the Commercial NGV Demonstration program, which encourages switching from using diesel trucks to the use of natural gas, conforms to the principle in the EEC Decision that promotes high to lower carbon fuel switching. While non-NGV programs in the Innovative Technologies Program Area reduce GHG emissions by encouraging residential, commercial, and industrial customers to reduce their overall consumption of natural gas, the Commercial NGV Demonstration program reduces GHG emissions by encouraging the adoption of NGVs in place of vehicles that use a higher carbon fuel. The end result is the same – GHG emissions reduction – in both types of programs.

10.1.1.4.3 Program Area Impacts

Each program area is impacted by the funding transfer in the following ways:

1) Conventional EEC Program Area (transferor)

- The funding transfer did not displace or discourage other potential program participants or initiatives, as the Conventional EEC expenditures did not reach the approved funding amounts available.

2) Innovative Technologies Program Area (transferee)

- The funding transfer did not displace or discourage other potential program participants or initiatives but rather supported and developed more innovative technologies program areas. This transfer also created a favourable TRC score of 1.2, which met the defined threshold for the Innovative Technologies Program Area as a whole.
- The Innovative Technologies Program Area provided incentive funding to four large fleet operators (for 82 vehicles in total) under the Commercial NGV Demonstration program. In the absence of a funding transfer, approximately only 32 NGVs would have been incented.

Impacting both program areas and all natural gas customers:

- The Companies' overall EEC portfolio level TRC, which includes both the conventional and innovative technologies program areas, is above the weighted average threshold of 1.0;
- Benefits are created for existing and future natural gas customers from increased natural gas throughput, which produces lower delivery rates, all else being equal,

through the Commercial NGV Demonstration program.[53] While load building benefits are not considered in the TRC test, they represent a positive impact to all natural gas customers; and

- As a result of the Commercial NGV Demonstration program, customers also benefit from estimated GHG emissions reductions of 20 – 30% due to fuel switching from higher-carbon diesel to lower-carbon natural gas. While GHG emissions savings are not considered in the TRC test, they represent a positive impact to all existing and future natural gas customers and the province.

Overall, the Companies believe its funding transfer has addressed the reporting obligations set in the EEC Decision and furthers overall EEC initiatives while benefiting new and existing customers.

10.1.1.5 Innovative Technologies Program Area Goals

The innovative technology programs pursue a number of objectives in order to support, review, and validate market-ready technologies. More specifically they focus on:

- Supporting local, provincial, and federal governments with climate action goals and policies and regulations focused on market-ready technologies; and
- Evaluating market-ready technologies and conducting pilot studies to validate manufacturer's claims about equipment and system performance and energy efficiency.

In support of the objectives outlined above, the Companies also strive to seek out new market-ready technologies as well as improving the awareness of existing ones. More specifically, their focus is to:

- Establish "proof of concept" projects based on certain methods, ideas, or market-ready technologies to demonstrate energy savings. This data will be used to confirm savings claims and guide the development of future programs;
- Conduct pre-feasibility studies to gauge the energy savings potential for market-ready technologies within the residential, commercial, and industrial sector;
- Initiate market assessments for technologies, methods, or ideas to gauge their conservation potential and market barriers within BC's climate;
- Coordinate measurement solutions with internal departments and/or third party companies to monitor systems performance and prospective energy savings. This data will be used to confirm savings claims and guide the development of future programs;

[53] The analysis of this benefit, for example, from the Commercial NGV Demonstration program, is discussed in Section 3 of FEI's Application for Approval of CNG and LNG Service submitted to the Commission on December 1, 2010.

- Replace existing low efficiency systems with innovative technologies to capture energy savings associated with reducing the overall consumption of natural gas and reduce GHG emissions and other air contaminants;
- Engage the trades community and manufacturers by supporting new, energy efficient technologies and installation protocols;
- Educate residential, commercial, and industrial customers about the advantages of innovative technologies and provide incentives for their adoption when necessary. The education channel may include demonstration projects as well as partner collaborations; and
- Develop cost effective programs within the Innovative Technologies Program Area to achieve a TRC ratio of greater than 1.0.

Objectives specific to the Commercial NGV Demonstration program focus on:

- Displacing diesel fuel consumption in the heavy duty transportation sector and replacing it with low carbon natural gas; and
- Reducing upfront capital cost barriers of NGVs for heavy duty trucking fleet operators to encourage the use of LNG and CNG as a transportation fuel.

10.1.1.6 Innovative Technologies Program Area Summary Status

Program descriptions for each of the Companies' Innovative Technologies Program Area offerings follow below. This table provides an overview of the innovative technology incentive programs, indicating which programs were completed in 2010, which programs remain active moving into 2011, and which programs are currently under development.

As can be seen in Table 10-1 below, the strong TRC result for the Commercial NGV demonstration program balances the lower TRC results for some of the other, pilot programs. Lower TRC results can be expected for many of the Innovative Technologies initiatives, reflecting the relatively high incremental cost for these initiatives which in turn is due to the low market penetration of the technologies at which the initiatives are aimed.

Table 10-1: Summary Status of Innovative Technology Programs

Program	Utility		Description	TRC	
	FEI	FEVI		FEI	FEVI
Completed Programs					
Solar Water Heating PSECA Program	X	X	Rebate program to encourage the adoption of solar water heating systems in provincial sector buildings to reduce natural gas consumption.	0.2	0.3
Active Programs					
Commercial NGV Demonstration Program	X		Rebate program to encourage the adoption of liquefied natural gas (LNG) and compressed natural gas (CNG) as a heavy duty vehicle fuel and to achieve environmental benefits to displacing diesel fuel.	1.4	N/A
Solar Air Heating PSECA Program	X		Rebate program to encourage the adoption of solar air heating systems in provincial sector buildings to reduce natural gas consumption.	0.4	N/A
SolarBC Schools Incentive Program	X	X	Rebate program to encourage the adoption of solar water heating systems in schools to reduce natural gas consumption and increase awareness.	0.2	0.2
Programs in Development					
Solar Residential Hot Water - PILOT PROGRAM	X		Rebate pilot program to assess the performance and energy savings for solar thermal hot water systems within the City of Vancouver.	0.2	N/A
City of Vancouver MURB - PILOT PROGRAM	X		Rebate pilot program to assess the viability of solar DHW, ventilation controls, and piping insulation for MURBs.	In Development	

10.1.2 2010 INNOVATIVE TECHNOLOGIES PROGRAM AREA RESULTS

As described in the 2009 EEC Annual Report, the Innovative Technologies Program Area includes funding categories for Solar Thermal Hot Water, NGV for Commercial Vehicles, Hydronic and Combination Space Heating Systems, Residential Ground Source Heat Pump ("GSHP") Systems, and Commercial and Industrial GSHP Systems.

The following table shows the program results from the innovative technologies programs currently in place.

Table 10-2: Innovative Technologies Portfolio Program Cost Breakdown - 2010 Program Area Results FEI/FEVI

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Solar Water Heating PSECA Program	$229	$143	$372	29,053	19,845	48,898	0.2	0.3
Commercial NGV Demonstration Program	$5,589	N/A	$5,589	(755,449)	N/A	(755,449)	1.4	-
Non-Program Specific Expenditures	$3	-	$3	N/A	N/A	N/A	N/A	N/A
Total	$5,821	$143	$5,964	(726,396)	19,845	(706,551)	1.2	

As program design progressed in Q3 2010, the Companies focused efforts on offering incentives for solar thermal hot water through the Public Sector Energy Conservation Agreement (PSECA) Funding program. The Solar Water Heating PSECA initiative is considered a program instead of a pilot since it was developed through the province and the Companies only served as a funding partner. Furthermore, the funds were necessary to support local, provincial, and federal governments through the PSECA Agreement in reducing greenhouse gas emissions as well as validating performance and energy efficiency claims. The data will be used to guide the development and feasibility of future Solar Thermal Hot Water programs.

The Solar Water Heating PSECA program, together with the Commercial NGV Demonstration program has a weighted TRC score of 1.0 or more on a program area level, thereby meeting the Commission's directive in Order No. G-141-09.

Within the Commercial NGV Demonstration program, two different fuel types have been pursued that reflect the two existing service offerings that FEI has for supplying natural gas for NGVs.[54] First, FEI has historically provided natural gas delivery service (or transportation) destined for the CNG transportation customers through Rate Schedules 6, 22, 23, 25, 26, and 27. Since FEI does not provide compression and dispensing service through these rates, customers must seek out fueling service providers to receive a complete end-to-end service offering. Commission Order No. G-65-09 issued on June 4, 2009, approved Rate Schedule 16 Interruptible Liquefied Natural Gas Sales and Dispensing Service ("Rate Schedule 16") as a five year pilot. Rate Schedule 16 gives the Company the ability to provide LNG supply in tank truck quantities from the Tilbury LNG bulk storage facility.

LNG as a transportation fuel is considered an emerging technology in BC and presently has no market penetration outside of small demonstration projects. Similarly, CNG has minimal market penetration as a heavy duty transportation fuel (except for approximately 50 transit buses), but was used in light duty vehicle applications in BC in the 1980s and 90s. Improvements in engine technology, combined with an attractive price differential between natural gas and diesel, have stimulated a new interest in CNG from heavy duty fleet operators in recent years. The Companies' CNG and LNG initiatives encourage heavy duty fleet operators of garbage trucks, waste haulers, buses, and Class 8 tractors to switch from high-carbon diesel to low carbon natural gas. Since the use of natural gas in heavy duty commercial vehicles has not been widely adopted in BC, the Companies' NGV initiatives are presently considered demonstration projects. While these technologies are well proven in other jurisdictions, it is important to assess performance under a BC context in a scalable manner. Projects using both CNG and LNG have been selected to demonstrate a complete fuelling solution for potential fleet customers (municipal and highway respectively). Limited experience with heavy duty NGVs exists in BC and the Companies believe it is appropriate to gain experience and data with its NGV initiatives through successful, demonstrable applications; therefore, NGV initiatives are deemed demonstration programs until data such as fuel consumption, fuel efficiency, and vehicle performance have been quantified in a BC context.

[54] At this time, NGV transportation Rate Schedules and proposed fueling service offerings have only been developed for FEI.

On December 1, 2010, FEI submitted an Application for Approval of General Terms and Conditions for CNG and LNG Service to the Commission, which, if approved, would provide NGV customers with a complete end-to-end service offering. The NGV incentives from EEC funds are not tied to fueling infrastructure installed by the Company, and fleets that self-supply the compression service and fueling station or procure it from another supplier are still eligible for EEC incentives. Thus, from the perspective of EEC funding, the effect of the NGV Application before the Commission is really that it makes it possible for more fleets to consider using NGV, and thereby increases the number of potential applicants for EEC incentives.

Work has not yet commenced in determining the viability of pilot programs for hydronic and combination heating systems or GSHPs.

10.1.3 2011 INNOVATIVE TECHNOLOGIES PROGRAM AREA OUTLOOK

In 2011, the TRC ratio for the entire Innovative Technologies Program Area is estimated at 1.8, which will meet the Commission's directives in Order No 141-09 for innovative technologies to have a weighted TRC score of 1.0 or more on a portfolio level. The relatively high TRC scores for NGV serve to balance the lower scores for some of the other Innovative Technologies initiatives.

Table 10-3: Innovative Technologies Portfolio Program Cost Breakdown – 2011 Program Area Outlook FEI/FEVI

Program	Incentives & Non-Incentive Expenditure ($000s)			NPV Energy Savings (GJ)			TRC	
	FEI	FEVI	Total	FEI	FEVI	Total	FEI	FEVI
Programs								
Commercial NGV Demonstration Program	$3,780	-	$3,780	(1,376,306)	-	(1,376,306)	1.9	-
SolarBC Schools Incentive Program	$22	$5	$27	3,046	716	3,762	0.2	0.2
Solar Air Heating PSECA Program	$73	-	$73	17,817	-	17,817	0.4	-
Pilots								
Solar Residential Hot Water - Pilot	$76	-	$76	4,829	-	4,829	0.2	-
City of Vancouver MURB - Pilot	In Development							
Studies, Memberships, Demonstration Projects (Non-Incentives)								
Geoexchange Energy Performance Study	$12	-	-	-	-	-	-	-
CESIG Gas Utilization Working Group Membership	$4	-	-	-	-	-	-	-
Westhouse Demonstration Project	$12	-	-	-	-	-	-	-
Total	$3,979	$5	$3,956	(1,350,614)	716	(1,349,898)	1.8	

10.1.4 2011 PROGRAMS

In 2011, the Innovative Technologies Program Area has allocated incentives for three programs including the Commercial NGV Demonstration program, SolarBC Schools Incentive program and the Solar Air Heating PSECA program. As shown in Table 10-3 above, the solar heating measures don't pass the TRC on an individual program level; but, together with other programs within the program area, the overall TRC ratio is over 1.0. The Companies feel programs and demonstration projects in the Innovative Technologies Program Area are necessary to support the climate action goals of local, provincial, and federal governments, as well as to displace diesel fuel consumption in the heavy duty transportation sector and replace it with low carbon natural gas.

Although innovative technologies are to be run as pilots and demonstration projects, the SolarBC Schools and Solar Air Heating PSECA initiatives are considered programs since they were developed through the province and SolarBC, and the Companies only served as a funding partner. Commercial NGV initiatives are presently considered demonstration projects for the reasons previously stated.

Fuel consumption data will be tracked and reviewed annually to determine fuel switching benefits and program roll-out approaches.

10.1.4.1.1 2011 Pilots

Funding from the Innovative Technologies Program Area has been committed to support and develop two pilot programs known as the Solar Residential Hot Water pilot and the City of Vancouver MURB pilot. The key objectives for those pilots are to support local, provincial, and federal governments with climate action goals, policies, and regulations, as well as gathering data and associated program savings for solar thermal technologies. The scope, measurement, and marketing plans for those pilots are currently being established.

10.1.4.1.2 2011 Studies, Memberships, and Demonstration Projects

In order to evaluate market-ready technologies, it is important for FEI and FEVI to participate in technology performance studies and industry memberships. The main objectives of these initiatives are to help validate energy savings claims and stay abreast with additional market available technologies, while collaborating and sharing costs amongst other gas and electric utilities. In 2011, the Companies committed $12,000 for a Geoexchange Energy Performance Evaluation Study and $4,000 for a membership to participate in The Centre for Energy Advancement through Technological Innovation ("CEATI") Gas Utilization working group. Additionally, the demonstration projects are important to not only experiment and confirm the energy savings potential of technologies but also to increase the awareness of the benefits of some of these technologies among the Companies' customers. Thus, the Companies committed $12,000 for the Westhouse Solar Demonstration project.

10.1.4.1.2.1 Geoexchange Energy Performance Evaluation Project

Phase 1 Geoexchange Energy Performance Evaluation Project	
Audience	Commercial, institutional, and multi unit residential buildings ("MURBs") that have an existing geoexchange system operational within BC's coastal and interior climates
Duration	Q2 2010 - Q2 2011
Commitment	$12,000

Partners	GeoExchange BC, FortisBC Inc., BC Hydro
Overview	
Description	The Companies have committed EEC funds for a Geoexchange Energy Performance Evaluation project initiated through GeoExchange BC. The goal is to evaluate the energy savings attributable to installed geoexchange systems in MURBs and commercial and institutional buildings. This research project will evaluate the electrical and natural gas consumption in existing buildings that have been equipped with geoexchange systems for at least three years. The study will report on the performance of a number of buildings of various types in both coastal and interior climates. The matrix of selected buildings will be designed to determine if the effectiveness of geoexchange technology is significantly influenced by (i) building type and (ii) heating dominant versus load-balanced systems.
Goals	• Evaluate and monitor systems performance and prospective energy savings for geoexchange systems. This data will be used to confirm savings claims and guide the development of future programs. • Strengthen relationships with program partners.
Deliverables	A concise, professionally written report summarizing the results supported by building descriptions and energy consumption data in an appendix. The consultant will also prepare a PowerPoint presentation for use by GeoExchange BC and the project's funding partners.
Implementation	
Administration	GeoExchange BC

10.1.4.1.2.2 Westhouse Solar Demonstration Project

Westhouse Solar Demonstration Project	
Audience	FEI and FEVI customers
Commitment	$12,000
Partners	City of Vancouver ("COV"), Simon Fraser University ("SFU")
Overview	
Description	The project is a collaboration between COV, SFU and FEI to demonstrate alternative energy in a high visibility collaboration and to gain information on the operation and energy performance of the solar thermal hot water system.
Goals	• Evaluate and monitor systems performance and prospective energy savings for geoexchange systems. This data will be used to confirm savings claims and guide the development of future programs. • Strengthen relationships with program partners.

	• To demonstrate alternative energy in a high visibility collaboration and to gain information on the operation and energy performance of the solar thermal hot water system.
Deliverables	City of Vancouver along with Smallworks will provide the house and property. FEIis to provide gas service along with solar equipment; SFU is to provide monitoring for the water and energy use.
Implementation	
Evaluation Strategy	Evaluation of the commitment will be determined from the number of visitors to the site and the usefulness of data collected from the system.

10.1.4.1.2.3 CEATI's Gas Utilization Working Group Membership

CEATI's Gas Utilization Working Group Membership	
Audience	Collaboration amongst gas utilities
Duration	Q2 2010 - Q2 2011
Commitment	$4,250
Members	Manitoba Hydro, Enbridge, ATCO Gas, NRCan
Overview	
Description	The Centre for Energy Advancement through Technological Innovation ("CEATI") is an international organization of utilities (predominantly electrical) that facilitates cooperation through focused interest groups and collaborative projects. Typically, CEATI projects and topics are forward looking at developing technologies that are not mainstream to the member utilities. The overarching principle is that through collaboration, member's dollars can be leveraged to involvement in a much greater number of projects and subject areas than would otherwise be available. CEATI operates on a paid fee basis for each of the interest groups ($8,500 per interest group). Value is obtained by the members through CEATI-sponsored projects, which are funded by the member utilities on a project basis, as well as an opportunity for networking, information sharing, and unofficial collaboration on projects that members may be undertaking. In 2010, CEATI created a new working group, the Gas Utilization Working Group under the Customer Energy Solutions Interest Group. The group has identified possible areas for collaboration that include: • Solar thermal • Motion sensor thermostats • Combined heat and power ("CHP") • Gasification of biomass • Water heater technology

Goals	• Investigate the market potential and energy savings for different market-ready technologies. • Collaborate with utilities and stakeholders on potential studies, pilots, and demonstration projects. This data will be used to confirm savings claims and guide the development of future programs. • Strengthen relationships with program partners.
Implementation	
Administration	The Centre for Energy Advancement through Technological Innovation

10.1.5 INNOVATIVE TECHNOLOGIES PROGRAM AREA DETAILS

10.1.5.1 Completed Programs

10.1.5.1.1 Solar Water Heating PSECA Program

Solar Water Heating PSECA Program	
Market	Retrofit
Audience	The program applied to provincial sector buildings including schools, universities, colleges, hospitals, and crown corporations
Duration	Q2 2010 – Q4 2010
Incentive	The Companies matched the incentive offered by NRCan, which was calculated by Performance Factor x Incentive Rate x Area of Collector x Number of Collectors. The incentives offered by SolarBC, NRCan and the Companies are used towards reducing the total solar hot water project cost for the participants.
Partners	SolarBC, BC Government SolarBC worked in partnership with the province to review and recommend projects for funding qualified solar thermal systems.
Background	
Description	The BC Government and the Companies entered into a Public Sector Energy Conservation Agreement (“PSECA”) to significantly increase energy conservation and, where feasible, expand the use of alternative energy options across more than 6,500 public sector buildings in British Columbia including Crown corporations, education and health care facilities, office buildings, social housing, and other government operations. A few alternative energy options were identified as solar thermal hot water and solar air heating. The BC Government through the PSECA is working with SolarBC to fund solar thermal water and air heating systems in provincial public sector buildings including schools, universities, colleges, hospitals, and Crown corporations. To support the province with the goals listed in the PSECA, the Companies provided $372,000 for 31 solar thermal hot water systems to be installed in those public sector buildings.

Goals	• Support local, provincial, and federal governments with climate action goals, policies, and regulations. • Evaluate market-ready technologies and conduct pilot studies to validate manufacture's claims about systems performance and energy efficiency. • Monitor systems performance and prospective energy savings. This data will be used to confirm savings claims and guide the development of future programs. • Develop cost effective programs with the Innovative Technologies portfolio with a TRC greater than 1.0 that optimize the proportion of incentives over administration and marketing costs.
Controls	• Eligible solar technologies must be CSA listed. • Finished projects must be commissioned by a P. Eng.
Implementation	
Administration	SolarBC and NRCan managed applications
Communications	FEI and FEVI submitted media releases, updated web content, and program promotion through Twitter.
Evaluation Strategy	Solar water heating consumption data analysis on the 2010 programs will be conducted one year from when all systems have been installed. A user acceptance survey will be sent to applicants to gauge challenges and successes of the technology. Sub metering solutions are also being discussed to measure the actual energy saving numbers.

10.1.5.1.1.1 2010 Actuals

Table 10-4: Innovative Technologies Solar Water Heating PSECA Program 2010 Actuals

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	20	$231	$0	2,579	29,053	0%	0.2
FEVI	11	$144	$0	1,683	19,845	0%	0.3
Total	31	$375	$0	4,262	48,898	0%	0.2

10.1.5.1.1.2 Discussion of Results

The Companies have committed incentive funding in 2010 to encourage the installation of 31 solar thermal hot water projects. Since the program is administered through SolarBC and there are minimal participants, both FEI and FEVI assumed a small non-incentive expenditure. As shown above, the solar heating measures do not pass the TRC on an individual program level but, together with other programs, the program area's TRC level passes the required threshold of 1.0 as shown under the 2010 Innovative Technologies Program Area results.

10.1.5.1.1.3 2011 Forecast

Funding offered under PSECA and NRCan's ecoENERGY for Renewable Heat are no longer available; therefore, the program is closed to further applications.

10.1.5.2 Active Programs

10.1.5.2.1 Commercial NGV Demonstration Program

Commercial NGV Demonstration Program	
Market	Original Equipment Manufacturer ("OEM") vehicles
Audience	Commercial, return-to-base fleet operators such as garbage trucks, waste haulers, buses, and Class 8 tractors
Duration	Q1 2010 - Q4 2011
Incentive	Incremental vehicle cost difference between an NGV vehicle compared to its diesel equivalent, up to a maximum of 100%
Partners	N/A
Overview	
Description	To encourage the adoption of CNG and LNG as a transportation fuel. Incremental vehicle cost incentive funding up to 100% is provided to qualified fleet operators of commercial, return-to-base heavy duty vehicles. This reduces the upfront capital barrier and initiates market adoption of NGVs, while achieving environmental benefits for the Companies' customers. CNG and LNG are low carbon fuels that offer economic benefits for fleet operators when compared to high carbon diesel. Other benefits include improved air quality and reduced noise in the communities and municipalities where such fleets operate. Finally, existing and future customers benefit from the increased natural gas throughput, which produces lower delivery rates, all else being equal. This increased load helps to offset the reductions from programs in the Conventional EEC Program Area and non-NGV programs in the Innovative Technologies Program Area.
Goals	• Displace diesel fuel consumption in the heavy duty transportation sector and replace with low carbon natural gas. • Reduce upfront capital cost barriers of NGVs for heavy duty trucking fleet operators to encourage the use of CNG and LNG as transportation fuels. • Encourage market adoption of CNG and LNG as transportation fuels in BC.
Controls	• The program must conform to the portfolio requirement of a TRC score of greater than 1.0. • A Contribution Agreement must be executed between the participant and the Companies detailing the terms and conditions of the incentive payment. • 50% of the funds will be advanced upon evidence of execution of a purchase order for the vehicles. This evidence is defined as an executed purchase order sent from the customer (or lesser) to the dealer, and copied to

	FEI/FEVI. The balance of the funds will be advanced when the vehicle is placed in regular service. These funds are advanced upon the receipt of a completed document from the customer stating the vehicle has entered regular fleet service. • The Companies reserve the right to demand repayment from the customer of any or all of the incentive amounts paid to the customer, if any of the natural gas fuel system components are removed from the NGV or if the NGV is removed from operation, or is relocated outside of the Companies' service territories within a negotiated period of time. • Successful applicants must undergo a confidential credit assessment conducted by the Companies. Only applicants with an "Approved Unsecured" rating will be considered.
Status	Round one "Calls for Expression of Interest" closed Q4 2010. Round two runs from Q1 2011 through Q4 2011.
Implementation	
Administration	The Companies' staff
Communications	Narrow business-to-business focus leveraged through industry associations and heavy duty truck dealers.
Evaluation Strategy	The Companies will monitor data provided by the participants on an ongoing basis. This includes data on kilometres driven, amount of natural gas consumed, and hours of usage (if available). This data will also be used to calculate and monitor GHG emissions reductions.

10.1.5.2.1.1 2010 Actuals

Table: 10-5: Innovative Technologies Commercial NGV Demonstration Program 2010 Actuals

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	82	$5,587	$2	(162,911)	(726,396)	0%	1.4
FEVI	Not Applicable						
Total	82	$5,587	$2	(162,911)	(726,396)	0%	1.4

10.1.5.2.1.2 Discussion of Results

In 2010, the Companies provided funding from the Innovative Technologies Program Area in the amount of approximately $5.6 million for 82 NGVs. This expenditure included approximately $4.4 million for 50 LNG vehicles and $1.2 million for 32 CNG vehicles. Incentive provisions have generated significant interest from the heavy duty transportation market and the Companies successfully provided funding to four fleet operators through this program. Non-incentive expenditures realized in 2010 were minimal as the means used to attract market participants did not involve incremental labour outside of the innovative technologies manager. Sales and marketing costs associated with the development of NGV initiatives are included in existing O&M budgets as approved in the NSA resulting from the 2010 - 2011 RRA.

A free rider rate of zero percent for 2010 was used as fleet operators would not switch to NGVs without an incentive. This is primarily due to the NGV price premium of 20 to 65 percent, which creates a high upfront capital cost for the operator in comparison to diesel vehicles.

The Commercial NGV Demonstration program is different from other EEC program areas in the sense that NGVs consume incremental volumes of natural gas, rather than conserve it; however, the fuel switching from high carbon diesel to low carbon natural gas generates an overall environmental benefit through a 20 – 30 percent reduction in GHG emissions just like other innovative technology programs.[55] The net benefit to the overall economy is fewer diesel litres of fuel being consumed by the transportation sector. As a result, a load building estimate of 162,911 GJ per year was calculated for 2010.

The Commercial NGV Demonstration program has not yet attracted participants within FEVI for two main reasons. Firstly, most high mileage fleet operators are based in the Lower Mainland and central regions of BC. Secondly, the higher delivery rate of natural gas within FEVI reduces the price differential between diesel and natural gas, and the overall attractiveness of CNG and LNG as a transportation fuel.

10.1.5.2.1.3 2011 Forecast

Table 10-6: Innovative Technologies Commercial NGV Demonstration Program 2011 Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	54	$3,780	$1	(228,131)	(1,376,306)	0%	1.9
FEVI	Not Applicable						
Total	54	$3,780	$1	(228,131)	(1,376,306)	0%	1.9

10.1.5.2.1.4 Summary

The Companies have entered into contractual commitments with three new fleet operators in 2011, for a total incentive expenditure of approximately $3.8 million for 54 vehicles. This includes approximately $3 million for 34 LNG vehicles and $803,000 for 20 CNG vehicles. These operators submitted applications for EEC funding and were subsequently approved by FEI. Furthermore, these operators are reputable leaders within the transportation industry, which is an important characteristic in selecting participants who can transform the industry and promote NGV adoption. The forecast expenditures of these commitments were calculated at a level of 100 percent of the incremental vehicle cost; however, FEI expects to decrease the level

[55] GHGenius.

of the incentive over time. As more NGVs are introduced to the market, the cost premium for NGVs and the risk perception associated with NGVs should both decline accordingly.

Later in 2011, subject to the successful resolution of the uncertainty surrounding the use of EEC funding for NGV incentive, the Companies intend to initiate a 'call for expressions of interest', whereby qualified fleet operators may submit an application for NGV incentive funding. This process would be communicated through industry associations such as the British Columbia Truckers Association and OEM truck dealers such as Inland Kenworth and Peterbilt. Depending upon the number and quality of applicants, the number of participants and incentive expenditures in the Commercial NGV Demonstration program could increase from the figures in Table 10-6 above; however, the Companies may contemplate lowering its 100 percent incremental incentive amount to a lesser percentage depending upon the number of participants in 2011. The actual percentage of funding to be provided in subsequent rounds of incentive awards has not been finalized at this point in time and will be determined in consideration of how effective the program has been in initiating market transformation. The Companies may also contemplate increasing non-incentive expenditures in 2011 as the number of applicants and approved operators may increase as a second round of calls takes place, creating further administrative costs. Further, since NGV initiatives have been developed through narrow, business-to-business channels, the Companies have not yet made a request for communications plan expenditures. Depending on the number of interested applicants, the Companies may contemplate additional communication channels in the future depending upon participant levels.

10.1.5.3 Programs in Development

10.1.5.3.1 Solar Air Heating PSECA Program

Solar Air Heating PSECA Program	
Market	Retrofit
Audience	The program will apply to provincial sector buildings including schools, universities, colleges, hospitals, and Crown corporations
Duration	Q4 2010 – Q2 2011
Incentive	The Companies will match the incentive offered by NRCan, which is calculated by Performance Factor x Incentive Rate x Area of Collector. The incentives offered by PSECA and the Companies are used towards reducing the total buildings' preheating cost for the participant.
Partner	SolarBC, BC Government SolarBC works in partnership with the province to review and recommend projects for funding qualified solar thermal systems
Background	
Program Description	The BC Government and the Companies entered into a Public Sector Energy

	Conservation Agreement ("PSECA") to significantly increase energy conservation and, where feasible, expand the use of alternative energy options across more than 6,500 public sector buildings in British Columbia including Crown corporations, education and health care facilities, office buildings, social housing, and other government operations. A few alternative energy options were identified as solar thermal hot water and solar air heating. The BC Government through the PSECA is working with SolarBC to fund solar thermal water and air heating systems in provincial public sector buildings including schools, universities, colleges, hospitals, and Crown corporations. To support the province with the goals listed in the PSECA, the Companies provided $73,000 for six solar air heating systems to be installed in those public sector buildings.
Technology Description	The solar air heating ("SAH") system preheats outdoor air that is required for ventilation. This reduces the heating demand for the conventional natural gas-fired heating section in the existing rooftop air-handling unit. The SAH system cladding is installed on the south facing building wall. The solar heated outdoor air rises through the collectors to a plenum at roof level. From the plenum, the air is ducted to the intake of an existing air handler where it is further conditioned (if required) and supplied to the building through the existing supply ductwork. Modulating dampers were included in the design to balance the temperature of the air during warmer weather. During summer months, when the outdoor air does not require heating, the SAH system is bypassed.
Goals	• Support local, provincial, and federal governments with climate action goals, policies, and regulations. • Evaluate market-ready technologies and conduct pilot studies to validate manufacturer's claims about systems performance and energy efficiency. • Coordinate measurement solutions with internal departments and/or third party companies to monitor systems performance and actual energy savings. This data will be used to validate energy savings claims and guide the development of future programs to a larger group of customers. • Strengthen relationships with program partners.
Controls	• Eligible solar technologies must be CSA listed. • Finished projects must be commissioned by a P. Eng. • Applicants that have the system installed after April 30, 2011 will not receive the incentive.
Implementation	
Administration	Program participation was facilitated through SolarBC and the BC Government. Applications were administered through NRCan and SolarBC.
Communications	Communications strategy initiated by SolarBC and the BC Government.

Evaluation Strategy	Consumption data analysis on the 2011 programs will be conducted one year from when all systems have been installed. A user acceptance survey will be sent to applicants to gauge challenges and successes of the technology. Sub metering solutions are also being discussed to measure the actual energy saving numbers.

As referenced in the 2009 Annual Report, the innovative technologies portfolio is not limited to developing programs for the preselected list of technologies such as solar thermal DHW systems, GSHPs, hydronic systems, sterling engines, or micro co-generation. The innovative technologies portfolio can include and evaluate additional technologies that have the potential for natural gas energy savings. One of the technologies that surfaced later in 2010 was dolar air heat through the Solar Air Heating PSECA program, and was therefore not forecasted in 2010. Solar air heat can be considered an emerging technology as there has been minimal exposure within British Columbia, but it is available commercially and can offer substantial natural gas energy savings.

10.1.5.3.1.1 2010 Actuals

The Solar Air Heating PSECA program was established in Q4 2010; therefore, no incentives were issued in 2010. Program incentives for the Solar Air Heating PSECA program are committed for 2011.

10.1.5.3.2 2011 Forecast

Table 10-7: Innovative Technologies Solar Air Heating PSECA Program 2011 Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	6	$73	$5	1,458	17,817	0%	0.4
FEVI	Not Applicable						
Total	6	$73	$5	1,458	17,817	0%	0.4

10.1.5.3.2.1 Summary

Solar air heat is included in the Innovative Technologies Program Area as there has been minimal exposure within British Columbia, but it is available commercially and may offer substantial natural gas energy savings. Since solar air technology is an emerging technology, there is a lack of information on system performance and energy savings within BC's climate. The baseline information provided through NRCans' RETScreen simulation tool supports the energy savings potential with this technology and manufacturer's claims. Further evaluation and sub-metering solutions are being discussed to measure the actual energy savings numbers and to support further program development.

The Companies have committed incentive funding in 2011 to encourage the installation of six solar air projects. Since the program is administered through SolarBC, the Companies did not assume a large non-incentive expenditure.

10.1.5.3.3 SolarBC Schools Incentive Program

SolarBC Schools Incentive Program	
Market	Retrofit
Audience	The program will apply to selected solar thermal hot water school projects administered by SolarBC with natural gas as a backup
Duration	Q4 2010 – Q1 2011
Incentive	The Companies will match the incentive offered by NRCan, which is calculated by Performance Factor x Incentive Rate x Area of Collector x Number of Collectors; therefore, the incentives vary per applicant. The incentives offered by SolarBC, NRCan, and the Companies are used towards reducing the total solar hot water project cost for the participant.
Partner	SolarBC
Overview	
Description	SolarBC, in collaboration with the Province of British Columbia, has initiated a Solar for Schools program to help reduce the carbon footprint and energy costs for schools, as well as providing a teaching opportunity about the possibilities for renewable energy usage and employment opportunities in the renewable energy sector. The Province of British Columbia provided $950,000 to encourage the installation of solar projects in schools through the SolarBC Program. Funding through SolarBC can be up to 90% of a project to a maximum of $20,000 per school across the province. The projects are approved via an application process through SolarBC. To support the province with those goals, the Companies committed $27,000 for eight solar thermal hot water systems to be installed in those schools.
Goals	• Increase the awareness of conservation as well as educating students and teachers on the benefits of solar hot water for domestic water heating within British Columbia's climate. • Support local, provincial, and federal governments with climate action goals, policies, and regulations. • Evaluate market-ready technologies and conduct pilot studies to validate manufacturer's claims about systems performance and energy efficiency. • Promote the continued growth and availability of local certified solar contractors throughout BC. • Encourage best installation practices to improve the quality and performance of the solar thermal hot water systems.

	• Strengthen relationships with program partners.
Controls	• Schools outside of FEI and FEVI's service territories are not eligible. • All systems require installation completed by a certified Canadian Solar Industries Association ("CanSIA") installer. • All collectors installed must be on the list of accepted solar collectors found at http://www.ecoaction.gc.ca/ecoenergy-ecoenergie/heat-chauffage/v2008/collectors-capteurs-eng.cfm. • 100% of the approved incentive will be advanced upon the receipt of an eco energy commissioning report, which is proof the solar hot water system has been successfully installed. • Consumption Analysis Test – the applicant's DHW assumptions need to be less than or equal to 5% of total GJ consumption to qualify for incentive. (*Based on Natural Resources Canada, Educational Services total natural gas [GJ] the average % DHW is 20% of the total natural gas consumption*.) For schools, since the average solar thermal system handles up to 20% of DHW load, the Companies felt it was conservative to add a control as a way to ratify GJ energy savings provided by the applicant. If the savings are stated to be greater than 5%, further analysis is required to determine building size and end use.
Implementation	
Administration	All applicants were administered through SolarBC and incentives approved through FEI and FEVI.
Communications	Communications to drive participation was facilitated through SolarBC.
Evaluation Strategy	Consumption data analysis on the 2010 programs will be conducted one year from when all systems have been installed.

10.1.5.3.3.1 2010 Actuals

The SolarBC Schools Incentive program was established in Q4 2010; therefore, no incentives were issued in 2010. Program incentives for the SolarBC Schools Incentive program are committed for 2011.

10.1.5.3.3.2 2011 Forecast

Table 10-8: Innovative Technologies SolarBC Schools Incentive Program 2011 Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	6	$22	$0	265	3,042	0%	0.2
FEVI	2	$5	$0	61	716	0%	0.2
Total	8	$27	$0	326	3,758	0%	0.2

10.1.5.3.3.3 Summary

FEI and FEVI have committed incentive funding in 2011 to encourage the installation of eight solar thermal hot water projects for schools. Since the program is administered through SolarBC and there are minimal participants, neither FEI nor FEVI assumed a large non-incentive expenditure.

10.1.5.3.4 Solar Residential Hot Water – PILOT PROGRAM

Solar Residential Hot Water – PILOT PROGRAM	
Market	Retrofit and new construction
Audience	The program will apply to residential applications within FEI's natural gas service area in Vancouver
Duration	Q1 2010 – Q4 2011
Incentive	$1,666 per approved application The level of incentives per participant works out to $1,666 each. This amount, along with $1,333 in partnership incentives, brings the total incentives for solar thermal hot water to $3,000 per system, which offsets approximately 43% of the installation costs.
Partner	City of Vancouver, Offsetters
Background	
Description	The City of Vancouver ("COV") has set in motion a solar hot water pilot program geared to prove the viability of solar energy in our climate for 30 residential applications. Their goals are to increase the adoption of solar hot water ("SHW"), reduce the city's carbon footprint, and create new green jobs. FEI, SolarBC, and Offsetters have partnered with the COV on this pilot initiative to gather real data on the performance and energy savings of SHW systems within this climate. The data will be used to confirm the viability of offering an EEC SHW residential program within British Columbia.
Goals	• Support local, provincial, and federal governments with climate action goals, policies, and regulations. • Measure and verify manufacturer's claims about systems performance and energy savings for selected residential homes within the City of Vancouver. This data will be used as the baseline to confirm savings claims and guide the development of future programs throughout BC. • Increase the awareness of and educate homeowners on the benefits of SHW for domestic water heating within BC's climate. • Promote the continued growth and availability of local certified solar contractors throughout BC. • Encourage best installation practices to improve the quality and performance of the solar systems. • Strengthen relationships with program partners.

Implementation	
Administration	Program participation and application processing is administered through Eaga and financed through SolarBC until March 31, 2011. After March 31, 2011 continued Eaga support will be financed through the COV.
Communications	FEI submitted media releases, updated web content, and promoted this pilot through Twitter.
Evaluation Strategy	Consumption data analysis on the 2010 programs will be conducted one year from when all systems have been installed. A user acceptance survey will be sent to applicants to gauge challenges and successes of the technology. Sub metering solutions are also being discussed to measure the actual energy saving numbers.

10.1.5.3.4.1 2011 Forecast

Table 10-9: Innovative Technologies Solar Residential Hot Water Pilot Program 2011 Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	30	$50	$26	420	4,829	0%	0.2
FEVI	Not Applicable						
Total	30	$50	$26	420	4,829	0%	0.2

10.1.5.3.4.2 Summary

FEI have committed $50,000 in 2011 to encourage the installation of 30 solar thermal hot water projects for residential homes within the City of Vancouver area. FEI also committed $26,000 for monitoring four of those solar thermal systems in order to measure and verify manufacturer's claims about systems performance and energy savings.

10.1.5.3.5 City of Vancouver ("COV") Multi Unit Residential Building ("MURB") – PILOT PROGRAM

COV MURB – PILOT PROGRAM	
Market	Retrofit
Audience	FEI Multi Unit Residential Buildings
Duration	Q2 2011 – Q4 2012
Incentive	To be determined
Partner	City of Vancouver

Background	
Description	The COV has set in motion a MURB pilot program intended to prove the viability of solar hot water ("SHW") along with ventilation controls and piping insulation in our climate for 15 MURBs. Their goals are to increase the adoption of SHW, reduce the city's carbon footprint, and create new green jobs. FEI has partnered with the COV on this pilot initiative to gather real data on the performance and energy savings of SHW systems for multi unit residential buildings within this climate. The data will be used to confirm the viability of offering an EEC SHW MURB program within British Columbia.
Goals	• Support local, provincial, and federal governments with climate action goals, policies, and regulations. • Evaluate market-ready technologies and conduct pilot studies to validate manufacture's claims about systems performance and energy efficiency. • Coordinate measurement solutions with internal departments and/or third party companies to monitor systems performance and prospective energy savings. This data will be used to confirm savings claims and guide the development of future programs. • Strengthen relationships with program partners.
Implementation	
Administration	City of Vancouver
Communications	To be determined.
Evaluation Strategy	Consumption data analysis on the 2010 programs will be conducted one year from when all systems have been installed. A user acceptance survey will be sent to applicants to gauge challenges and successes of the technology.

10.1.6 SUMMARY

Innovative technologies represent an important component of the Companies' overall commitment to EEC activities. Since being staffed with a manager at the end of Q2 2010, the Companies have enhanced the program's framework, established relationships with key industry stakeholders, and evaluated market-ready technologies. Approximately $5.9 million of the EEC funds were committed in 2010 to support local, provincial, and federal governments with climate action goals, policies, and regulations, as well as establishing evaluation best practices to monitor systems performance and prospective energy savings. The Companies will further evaluate program design and continue to investigate, evaluate, and pilot market-ready technologies such as solar thermal hot water, solar air heating, and others in 2011. Subject to the successful resolution of the uncertainty surrounding NGV incentive funding arising as a result of the Commission's recent commentary on this issue, the Companies also intend to initiate a 'call for expressions of interest' whereby qualified fleet operators can submit applications for 2011 CNG and LNG incentive funding. The weighted TRC ratio for the entire

Innovative Technologies Program Area for both 2010 and 2011 is positive and meets the Commission's directives in Order No. 141-09 for innovative technologies to have a weighted TRC score of 1.0 or more on a portfolio level.

10.2 Funding for NGV Initiatives

10.2.1 DEFINITION

NGVs represent an important element of the Innovative Technology Program Area, and the favourable TRC of NGV related incentives has contributed in a large measure to the favourable TRC of the overall Innovative Technology portfolio. This Section specifically deals with the Commission's recent comments regarding whether FEI has approval to proceed with NGV related programs. It provides additional information regarding why the Companies believe that they are compliant with past Commission orders, and also provides further information about the benefits associated with the funding which have contributed to stakeholder support for these initiatives. It is the hope of the Companies that the Commission will be able to quickly provide confirmation of the Companies' compliance with past orders without additional process. Alternatively, if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission provide its concurrence for the Companies to proceed with EEC incentive funding to customers to offset the incremental cost of buying an NGV over a standard gasoline or diesel vehicle. The Companies respectfully submit that this concurrence to proceed could also be provided without additional process since the benefits of EEC incentive funding for NGV are clear, accord with Commission-approved EEC principles, exceed the Commission-approved tests for evaluating EEC funding, and have the support of stakeholders.

This section is organized as follows:

- The Companies first set out the Commission's comments that gave rise to this issue, and provide their views as to why this matter is most appropriately resolved in the context of this Report; and
- The Companies then outline the key elements of past decisions that support the Companies' actions to date, and support the continued use of cost effective NGV incentives.

10.2.2 COMMISSION'S COMMENTS ON FUNDING FOR NGVS AND NEED FOR QUICK RESOLUTION

On January 14, 2011, the Commission released its Order No. G-6-11 and decision ("Interim Decision"), which approved a CNG Fueling Station Installation and Operating Agreement between FEI and Waste Management of Canada Corporation on an interim basis, subject to certain conditions. In this Interim Decision, the Commission raised a potential issue with respect to the use of EEC incentives for NGV vehicle reimbursement. The Commission's Interim Decision, Appendix A, page 5, stated:

> *"The Commission Panel is not presently persuaded that Terasen has Commission approval for the incentive grant to Waste Management that is described under Vehicle Reimbursement in the WM Agreement. Directive 2 of Order G-36-09 explicitly rejected expenditures for Natural Gas Vehicles. The Negotiated Settlement approved by Order G-141-09 approved Rate Schedule 26 – NGV Transportation Service and marketing costs in support of NGV. Terasen withdrew its other requests related to NGV. Rate Schedules 6 and 26 provide for NGV incentive grants, but it seems unlikely that Waste Management will use these Rate Schedules. Therefore, the Commission Panel believes that Terasen is at risk of not being able to recover incentive payments to Waste Management in its rates."*

As FEI outlined in its response to BCUC CONFIDENTIAL IR 1.4.1, contained in the Application for Approval for a Service Agreement for Compressed Natural Gas Service and for Approval of General Terms and Conditions for Compressed Natural Gas Liquefied Natural Gas Service, dated December 20, 2010, that TGI intended "to continue meeting its reporting commitments by reporting in the next annual EEC report on the WM funding, and any matters relating to TGI's use of EEC funding should be addressed at that time…". The Commission did not have the benefit of a complete background and analysis when it made its comments regarding EEC funding for NGVs, and recognized that "the incentive payments are outside the scope of the review of the WM Agreement"[56] in its Interim Decision.

What follows below is our commitment to provide all information related to why we believe we have acted within the guidelines and approvals of past regulatory decisions related to EEC, specifically to the use of EEC incentives for NGVs. The information included in this Report adds to the information available on the record in the proceeding where the Commission made its comment about EEC funding. As such, there is now a complete record on which the Commission can determine this issue.

The Companies submit that this Report is the most appropriate forum to seek concurrence on this issue, rather than deferring the matter to the upcoming revenue requirements application, for four reasons:

1. The first expenditures from the EEC funding envelope for NGV occurred in 2010, to which this Report speaks. The individual spend by program areas is contained within this Report along with the individual and portfolio level TRC to which EEC incentives for NGV contribute.
2. The EEC Annual Report was established to ensure the Companies are operating within the guidelines and approvals established in Order No. G-36-09 and sequence Orders G-140-09 and 141-09.
3. The Companies have put further EEC incentive awards for NGVs on hold until the uncertainty is resolved. Prolonged delays in resolving this matter will likely delay the delivery rate benefits obtained by existing non-bypass customers associated with building cost-effective load, delay the benefits achieved by new NGV customers from reduced

[56] Order No. G-6-11 Appendix A page 5.

transportation costs, and delay GHG emissions reductions in BC. These delays could potentially derail NGV initiatives (and its associated benefits) completely if fleet operators adopt conventional or viable alternative technologies.

4. The Companies' position for why we believe we have approvals to use EEC funds for NGVs is contained below and this makes for an efficient and less costly process to resolve this issue for all parties involved.

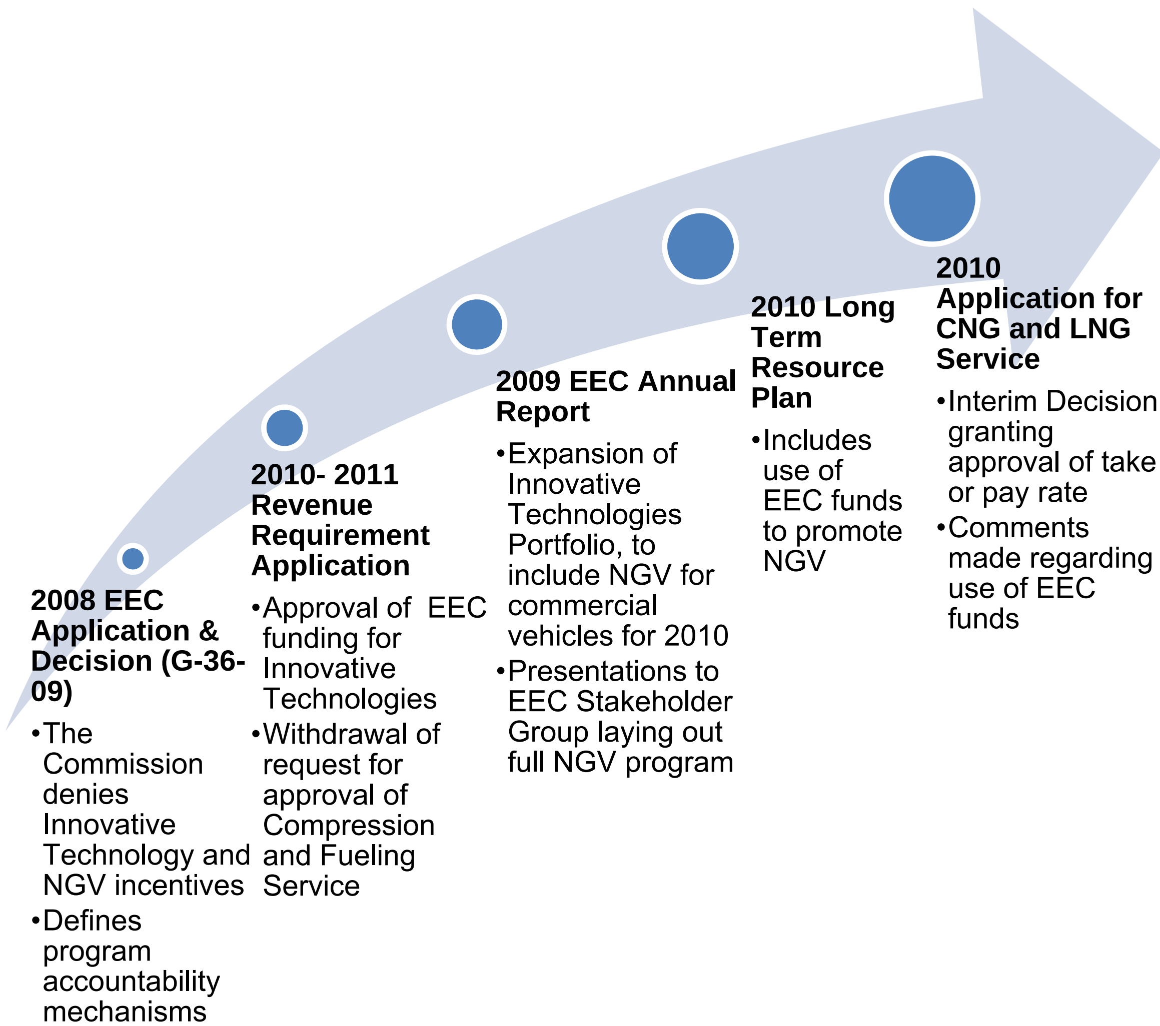
The Companies have support from key stakeholders for the quick resolution of this uncertainty resulting from the Commission's interim order on Waste Management, and the re-initiation of NGV incentive programs. As a result of a recent EEC Stakeholder Group held March 15, 2011, FEI has received letters from multiple members of the Stakeholders Group supporting FEI has followed the established process in the use of EEC funding (Please see Appendix F for copies of these letters). The Companies thus submit that the necessary information is now available to address this issue in a meaningful way.

10.2.3 RELEVANT COMMISSION APPROVALS

There have been a number of regulatory events that led up to the Companies providing NGV funding. In this section the Companies outline the key aspects of past Commission orders that support NGV funding. As explained in detail below, FEI believes that the use of Innovative Technologies Program Area EEC funding for NGV initiatives is consistent with previous Commission decisions (Orders G-36-09, G-141-09, and G-140-09), and that FEI has been open and transparent with stakeholders about EEC activities and expenditures, including the use of EEC incentives for NGV.

The following diagram summarizes the sequence of regulatory proceedings and events that touch on EEC funding.

Figure 10-1: Timeline of Regulatory Proceedings Related to EEC Funds and NGV



Each of these regulatory events and how they impact the Companies' use of EEC funds for NGVs is discussed in detail in the remainder of this Section, which is structured as follows:

1. EEC Application and Decision (Order No. G-36-09, dated April 16, 2009)
    a) Rejecting EEC funding for the Innovative Technology Portfolio, including Natural Gas Vehicles
    b) Recognizing and establishing principles applicable for developing further programs within the Innovative Technologies Program Area, including that
        i. Programs on a portfolio level must meet an established threshold

ii. Innovative Technologies Program Area brings forward the benefit of lower GHG emissions by promoting low carbon technologies

c) Setting up mechanisms for introducing new programs and making refinements to existing programs through the Commission approved accountability and oversight measures, including

i. Stakeholder Input and Reporting
ii. The Company's ability to transfer funds between program areas within the EEC funding envelope.

2. The 2010/2011 Revenue Requirements Application ("RRA") and Negotiated Settlement Agreement ("NSA") (Order No. G-141-09 and G-140-09, dated November 26, 2009)

a) Two Distinct Proposals Presented in the 2010/2011 RRAs for EEC and NGV fuelling station infrastructure, and the one that was withdrawn in the NSA did not relate to EEC

- Items 11 and 12 of the NSA for FEI are for EEC initiatives and programs. Items 6 and 7 of the NSA for FEVI are for EEC initiatives and programs

- Item 14 of the NSA for FEI, which the Commission has alluded to in its recent Decision accompanying Order No. G-6-11 as having been withdrawn, is NGV for fuelling and transportation service (delivery on the FEI system), not EEC funds for NGV. Also, item 9 of the NSA for FEVI is NGV for fuelling and transportation service (delivery on the FEI system), not EEC funds for NGV.

i. Increased EEC Funding Approvals for 2010 and 2011, including Innovative Technology and Industrial Programs and Innovative Technology programs are to be evaluated as a separate portfolio

ii. Withdrawal of NGV Rate Offering, not related to EEC funds

3. Adhering to the principles and framework established by Commission Decisions with regard to the use of EEC funds for NGVs

a) Favourable TRC Ratio
b) GHG emissions reductions benefits
c) Broad support from EEC Stakeholder Group Consultation
d) Openness and transparency in the 2009 EEC Annual Report and 2010 Long Term Resource Plan

Each of these topic areas are discussed in detail below.

10.2.3.1 EEC Application and Decision

The Companies filed an EEC Application on May 28, 2008. On April 16, 2009, the Commission issued Commission Order No. G-36-09 (the "EEC Decision"). While the specific request for

Innovative Technology funding was denied, the Decision established important principles and framework as to how FEI should evaluate EEC programs (primarily the TRC test, on a portfolio basis), and established a specific regulatory mechanism for overseeing the Company's use of EEC funding (the EEC stakeholder committee). These approvals become important later in the chronology, as the NGV funding meets the approved test for evaluating EEC funding, and the use of EEC funding for incentives was presented to, vetted by, and generally supported by, the stakeholder committee as confirmed by the letters of support filed with this Report.

10.2.3.1.1 Rejection of the Innovative Technology Portfolio Including Natural Gas Vehicles

In the EEC Application, funding for NGV initiatives was sought under the umbrella of "Innovative Technologies, NGV and Measurement", because all these programs aim "to foster and further the deployment of forward-looking low carbon technologies" (Page 69 of the EEC Application). In the EEC Decision, the Commission rejected funding for the Innovative Technology, NGV and Measurement Program Area based on "insufficient evidence" at that time. In particular, the EEC Decision (on Page 26) states:

> *…Terasen acknowledges that further refinement of this program is required and indicates uncertainty as to whether an effective program can be developed over the funding timeframe. The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed.*

Thus, although the Commission rejected the funding "at this time," it did not reject the possibilities that NGV programs be developed. Additionally, there are two other relevant parts of the EEC Decision, discussed in the following paragraphs: (1) the approval of the TRC test for evaluating programs by adopting the portfolio approach, and (2) the EEC stakeholder group being established as the means of efficiently reviewing EEC program spending.

10.2.3.1.2 Recognition and Establishment of Certain Principles

The Commission granted a number of other approvals, significant among which for the current issue was the approval of a method for evaluating EEC initiatives. The EEC incentives for NGVs meet the approved tests.

10.2.3.1.2.1 TRC Meets the Established Threshold

FEI assesses all EEC funding according to the framework established in the EEC Decision, which involves, among other things, the application of TRC test, which measures the cost-effectiveness of the EEC programs.

The Commission discussed the application of a TRC at page 34 of the EEC Decision:

> *The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this EEC Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such.*

Furthermore, the Commission accepted a portfolio level approach when considering the TRC ratio. That is, all EEC programs, on an overall combined level, rather than on individual initiatives or programs, should achieve a portfolio TRC level of 1.0 or greater.

Thus, the cost effectiveness of EEC expenditure is evaluated as a whole, on the portfolio level, which must have a TRC test of one or greater.

Please refer to Table 10-2 which shows the TRC for the Innovative Technologies portfolio as a whole including the Commercial NGV Demonstration program for 2010.

10.2.3.1.2.2 GHG Emissions Reduction by Promoting Fuel Switching From Higher Carbon Fuel to a Lower Carbon Fuel

In the EEC Application, FEI and FEVI had applied for approval of funding to encourage the adoption of natural gas as a fuel instead of both higher carbon fuels and electricity in the residential sector. The Commission accepted the former, and rejected the latter. As per page 18 of the EEC Decision:

> *The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas.*

We acknowledge that fuel switching was addressed in the EEC Application in the context of the residential sector, and that this statement did not represent Commission approval to pursue fuel switching in the transportation sector. (The Companies submit that the approval to do so came later, following upon the Commission's approval of the 2010-2011 Revenue Requirements Application Negotiated Settlement Agreement.) However, this recognition of the benefits of high to low carbon fuel switching speaks to the Companies' rationale for pursuing NGV incentives. Not only does using NGV technologies in the transportation section move customers from higher carbon fuel such as diesel to low carbon natural gas, but also the principles underlying the fuel switching and underlying all the Innovative Technologies Program Area are consistent – reduction of the GHG emissions. Please refer to Section 10.2.3.3.2, which outlines the GHG emissions reduction in 2010 from providing EEC incentives to NGVs.

Since the EEC Decision was issued, Government enacted the *Clean Energy Act ("CEA").* Reducing GHG emissions in BC is one of the main objectives of the provincial government, as outlined in the *CEA*. In fact, the *CEA* includes as one of "British Columbia's energy objectives"

GHG emissions reduction by high-to-low carbon fuel switching, which is directly applicable to NGVs.[57]

This, too, speaks to FEI's rationale for looking to the transportation sector as a potential target for EEC incentives.

10.2.3.1.3 Commission Approved Accountability Mechanisms for Introducing New Programs, and Refining Existing programs

The EEC Decision also included approvals of mechanisms that would ensure accountability for EEC expenditures. The approval for accountability mechanisms is more efficient than the Companies seeking Commission approvals each time funding was redirected, while, similar to the approval of inter and intra program area funding transfers, providing flexibility to the Companies in managing and developing EEC programs.

These approvals are important in the current context, not because they approved spending on NGV incentives, but because the Companies followed this framework once funding for Innovative Technologies incentives was approved in the 2010-2011 RRA NSA. By following this framework, the Companies have kept stakeholders fully apprised of our intentions regarding NGV incentives, and stakeholders have had input in to how it was done.

10.2.3.1.3.1 Stakeholder Input and Reporting

In the EEC Application, the Companies proposed accountability mechanisms for managing the funds approved for EEC programs. Specifically, the EEC Decision, at page 41, summarizes what was proposed:

> *In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. [Emphasis added]*

Interveners supported this funding approach, as stated on page 41 of the EEC Decision:

> *BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than*

[57] Clean Energy Act, section 2, "British Columbia's energy objectives"

> *having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)*

The Commission accepted these accountability mechanisms on page 42 of the EEC Decision:

> *The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.*

Once the 2010-2011 RRA NSA was in place, with its recognition of funding for Innovative Technologies, the Companies employed the accountability mechanisms approved in the EEC Decision for Innovative Technologies in the same manner as with all other EEC spending. For the Commercial NGV Demonstration program, the EEC Stakeholder Group was consulted on three occasions, as outlined below in Section 10.2.3.3.2.1.

10.2.3.1.3.2 Flexibility to Manage Funds for Approved Program Areas

With accountability mechanisms in place, FEI believes that the Companies should be provided the flexibility in managing the approved funds to further achieve efficiency. In the EEC Application, the Companies state:[58]

> *…that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the Funding Period, rather than approving the funding by program area, or by individual program initiative. <u>This approach will allow the Companies' to respond quickly to changes within initiatives and to new opportunities that might arise.</u> For example, if a particular initiative within the commercial energy efficiency program area has a higher than expected number of participants, and a strong cost-benefit ratio, the Companies would like to have the ability to shift funds from another, underutilized program area to that commercial energy efficiency initiative, without coming back to the Commission for approval to do so. Not only will this allow the Companies' to respond quickly to opportunities, <u>it will also reduce the Companies' administrative burden related to EEC activity, and both the speed of response and reduced administrative burden will increase the value to customers of the Companies' EEC activity.</u>* [Emphasis Added]

The EEC expenditures approved in the EEC Decision are part of a funding envelope to develop and implement programs that conform to meeting the portfolio TRC of one or greater than one, and FEI has the ability to transfer funds to where it makes the most sense provided it can be

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[58] EEC Application, at pages 50 and 51

justified after the fact in a Report. FEI requires the flexibility to move funds to programs like the EEC expenditures for natural gas vehicles so that programs can be designed and implemented efficiently within an approved funding envelope. The measure for determining whether or not the expenditure was made appropriately is the TRC test, and FEI's reporting obligations permit the regular assessment of FEI's expenditures. The Commission addressed reporting obligations on page 42 of the EEC Decision, and expressly anticipated that shift in funding within the overall approved envelope would be allowed provided that such a transfer is transparent and supported with reasons:

> *Commission Panel directs that the annual EEC Report include the following:*
>
> *• TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.*
>
> *• <u>any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be</u>.* [Emphasis Added]
>
> *• data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.*

While this direction does not authorize spending outside of Commission-approved Program Areas, it does speak to the use of funds within those approved areas being managed by the Companies, with accountability to the EEC Stakeholder Group regarding the funding decisions as part of the annual reporting. Once the 2010-2011 RRA NSA was in place, with its recognition of funding for Innovative Technologies, FEI proceeded to design incentive programs and used EEC incentives in line with the approved tests. The oversight of those decisions occurred in the context of the EEC Stakeholder Group, in the same manner as with all other EEC spending. For the Commercial NGV Demonstration program, the EEC Stakeholder Group was consulted on three occasions, as outlined below in Section 10.2.3.3.2.1.

As described in the Evaluation Strategy of the Commercial NGV Demonstration program (in Section 10.1.5.2), fuel consumption data will be tracked and reviewed annually to determine fuel switching benefits and program roll-out approaches. This data will be used to calculate and monitor the estimated GHG emission reduction benefits.

10.2.3.1.4 <u>Summary: Providing EEC Incentives to Natural Gas Vehicles is Consistent with the Principles Contained in the EEC Decision</u>

While the EEC Decision rejected specific funding for the Innovative Technologies Program Area, the Decision establishes certain principles and provides framework for the Company to consider when developing and bringing forward programs in this Program Area. Specifically, the Commission:

- Recognized the benefits of high to low carbon fuel switching in the residential context;

- Adopted the use of TRC test on a portfolio level to assess the cost-effectiveness of the EEC programs;
- Approved the proposed accountability mechanisms to oversee the use of funds for approved Program Areas, including annual report to the Commission and consultation with Stakeholder groups, for development of new programs and refinement to existing programs; and
- Accorded the Companies flexibility to manage the funds subject to the accountability mechanisms.

Following the approval of the EEC funding for Innovative Technologies Program Area in the 2010-2011 Revenue Requirement Application proceeding, the Company developed the NGV programs using EEC funding consistent with these principles and the framework.

10.2.3.2 2010-2011 Revenue Requirements Application and Negotiated Settlement Agreements

Subsequent to Commission's Order No. G-36-09 in which the Commission left it open to the Companies to propose Innovative Technology programs, FEI and FEVI sought increased EEC funding approval to add specific programs under Innovative Technologies and Industrial Program Area in their respective 2010-2011 Revenue Requirements Applications. As discussed below, the settlement agreements that resolved these Revenue Requirements Applications included Innovative Technology funding envelope based on the Companies' proposal.

In several responses to Information Requests issued in the Revenue Requirements Applications regarding NGVs, the Companies expressed its intent to use different sources of incentive funding to overcome the high fleet conversion costs and limited number of OEM vehicles, including grants already available and "all available funding opportunities", a reference to using EEC funding that had been proposed. For example, in response to BCUC IR 1.34.2 in the RRA proceeding, FEI stated:

> *TGI intends to meet the other potential obstacles by providing grants, and ensuring that all available funding opportunities are used.*

Both applications were subject to Negotiated Settlement Agreements. On November 26, 2009, the Commission released Order No. G-141-09 and G-140-09 approving NSAs for FEI and FEVI respectively. Thus, the total funding envelope for EEC increased with these two decisions; however, the underlying principle contained in Order No. G-36-09 must be adhered to in order to make use of these funds.

The Commission's approved the NSA's included the approval of EEC funding for Innovative Technologies for FEI and FEVI for 2010 and 2011. These approvals are explicitly described in Items 11 and 12 in the FEI's NSA and Items 6 and 7 in the FEVI's NSA.

Associated with these approvals, both NSAs state that:

> *…the Innovative Technologies Programs will be managed by [the Companies] as a separate segment of the overall portfolio to have a weighted average Total Resource*

> *Cost ("TRC") of 1.0 or more. [The Companies] will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.*

The last sentence suggests that the Companies will continue to work with the EEC stakeholders to develop or refine programs/applications to achieve the established TRC threshold. This conforms to the principle and framework provided under the EEC Decision. NGV incentives, because of having a TRC well above 1.0, make a significant contribution to ensuring that the Innovative Technologies portfolio maintains a portfolio TRC greater than 1.0.

10.2.3.2.1 Two Distinct proposals presented in the 2010-2011 RRA for EEC Funding and NGV Rate Offerings

In its Reasons for Decision, accompanying Order No. G-6-11, the Commission commented that in the 2010-2011 RRA proceedings, the Companies "withdrew its other requests related to NGV" besides incentive grants under Rate Schedules 6 and 26.[59] The Companies respectfully submit that the Commission's comments reflect that it mixes two distinct issues addressed in separate sections of the NSAs: EEC funding and NGV rate offerings. The NSA granted express approval of the EEC funding requests.

In their respective Revenue Requirement Applications, the Companies made two distinct requests for approval: (1) EEC funding for Innovative Technologies Program Area, and (2) NGV Rate Offerings. For instance, in FEI's RRA (dated June 15, 2009 at page 227), FEI submitted six separate proposals in the context of its EEC and Alternative Energy Solutions initiatives. Two of these distinct proposals are:

> *" 1. Increase EEC funding for 2010 over the currently-approved EEC funding to add interruptible Industrial customer programs and Innovative Technologies programs to the EEC portfolio, with all funding subject to the same financial treatment as approved in the EEC Decision;*
>
> *5. Approval of Tariffs for Rate Schedule 6C – Natural Gas Compression and Refuelling Service and Rate Schedule 26 – Natural Gas Vehicle Transportation Service, and subsequently the cancellation of Rate Schedule 6A – General Service – Vehicle Refuelling Service."*

Item 5 listed above pertains to "Natural Gas Vehicle Rate Offerings", which FEI further described in its 2010-2011 RRA.[60] Specifically, FEI sought approval of Rate Schedule 6C – Compression and Refuelling Service, Rate Schedule 26 – NGV Transportation Service, and their supporting activities - Compression Service ("CS") test parameters and a NGV non-rate base deferral account. The requests for EEC funding and for natural gas vehicle rate offers are independent of each other in the context of the RRA.

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[59] Order No. G-6-11, at page 5.
[60] FEI 2010-2011 RRA at pages 238 to 249.

10.2.3.2.1.1 EEC Funding Increase Request

The EEC funding request was approved in FEI's NSA, as Item 11 and Item 12 for FEI's NSA as Items 6 and 7. For example, Item 11 of the NSA is outlined here:

11. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:

(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[61] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.

(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.

(c) EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee. [Emphasis added.]

Thus, the Innovative Technology funding was approved.

10.2.3.2.1.2 Withdrawal of NGV Rate Offering Request

With respect to natural gas vehicle rate offerings for FEI, Rate Schedule 26 was approved as filed; however, the other items related to the NGV Rate Offerings were subsequently withdrawn. To reach a settlement on requests in the RRA as a whole, FEI withdrew its request for NGV Rate Offerings, as described in the excerpt below. However, this was treated as distinct from the approval of EEC funding.

Relating to FEI, Item 14 from Page 10 of the NSA approved in Order No. G-141-09 states:

14. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

[61] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

"Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 - NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

i. <u>Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV</u>

<u>Refueling Service; and</u>

<u>ii. the Compression Service ("CS") Test; and</u>

<u>iii. NGV non-rate base deferral account.</u>

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so. [Emphasis added.]

Thus, what was withdrawn by FEI only related to natural gas vehicle rate offerings (compression and fueling service). However, the use of EEC funds for NGVs was not withdrawn as part of the NSA; FEI was given express approval to pursue initiatives targeted at Innovative Technologies. When developing the Innovative Technologies programs, which the Companies believe that NGVs are to be part of, and have expressly stated so in 2008 EEC Application and the 2009 EEC Annual Report, the Companies would still have to adhere to the principles contained in Order No. G-36-09 as outlined above to use EEC funds for NGVs.

FEI has also received support for this interpretation of the NSA from a member of the EEC Stakeholder Group who was also a registered intervener during the RRA proceeding. In a March 22, 2011 letter[62] to FEI, the Commercial Energy Consumers Association of BC ("CEC") stated the following:

…The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process ("NSP") but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV

[62] Please see Appendix F for a copy of the letter from CEC

initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011.

The Companies agree with CEC's characterization of the agreement.

10.2.3.3 The Companies Have Adhered to the Principles Established By Commission Decisions with regard to the use of EEC funds for Natural Gas Vehicles

The Companies' use of the EEC funding for the Innovative Technologies Program Area to develop NGV programs, subsequent to the RRA NSAs, has met the principles and framework established in the EEC Decision and further developed in the NSAs approved by Commission Orders G-141-09 and G-140-09, as described in Section 10.2.3.1.3 in terms of evaluation, oversight and accountability. The factors relevant to the evaluation, oversight and accountability are discussed below.

10.2.3.3.1 Favourable TRC Ratio

Pursuant to the approved NSAs, the Companies must manage the Innovative Technologies Program Area as a separate segment of the overall portfolio and the TRC ratio for this segment must have a weighted average TRC of 1.0 or more.

The Innovative Technologies Program Area described in this Report has met this threshold with a weighted average TRC of 1.2. As summarized earlier, see Table 10-10 below for the Innovative Technologies Program Area TRC for 2010.

Table 10-10: Innovative Technologies Program Area TRC for 2010

Program	TRC	
	FEI	FEVI
Solar Water Heating PSECA Program	0.2	0.3
Commercial NGV Demonstration Program	1.4	-
Total	1.2	

The Commercial NGV Demonstration program has made a significant contribution to ensuring that the overall TRC for the Innovative Technologies portfolio has exceeded 1.0.

10.2.3.3.2 GHG Emissions Reductions Benefits

As the Commission recognized, the Innovative Technologies programs can be effective tools for achieving GHG emission reductions. Similar to the residential fuel-switching program, the Companies have tracked and demonstrated that the Commercial NGV Demonstration program creates GHG emissions reduction benefits. The NGVs incented in the 2010 Innovative

Technologies Program Area are expected to produce between 20 - 30% fewer GHG emissions than their diesel counterparts.[63] At this time, FEI estimates that the vehicles under the 2010 program expenditures represent annual GHG savings of approximately 4,100 tonnes of CO2e per year, which is the equivalent to taking 800 passenger vehicles off the road.[64] As these NGVs enter regular operations FEI will track and monitor fuel consumption and distance traveled, which is used to calculate GHG emissions.

10.2.3.3.2.1 Broad Support from EEC Stakeholder Group Consultation

As stated above, one of the key principles developed through the EEC Decisions and the subsequent approved NSAs is the accountability mechanism that allows for oversight by the stakeholder groups. In accordance with this principle, an EEC Stakeholder Group was formed in December of 2009 (Please see Section 12: EEC Stakeholder Group Activities). The members of the EEC Stakeholder Group were solicited through regulatory stakeholders (those that have historically intervened in the Companies' regulatory proceedings), from industry groups with whom the Companies interact, and from key contacts from the Companies' Energy Solution and Community Relations departments. Additionally, the Companies have also done the following:

- On March 11, 2010, the proposed Innovative Technologies portfolio was presented to the EEC Stakeholders meeting (Please see Appendix H for a copy of this presentation and a copy of the attendees list). In particular, at the meeting, the Companies provided estimates of funds to be applied to various Innovative Technologies Program Area, including NGVs (see slides 5 and 6). The meeting also achieved several important goals, such as:[65]
  a) Providing an opportunity to discuss details of how the weighted average TRC is applied to the Innovative Technologies portfolio.
  b) Allowing the EEC stakeholder group to discuss proposed Innovative Technologies program portfolio and program costs.
  c) Introducing the group to the feedback mechanism that affords them an opportunity to voice any concerns on the approach to Innovative Technologies, and to provide ongoing dialogue.
- Following the March 11, 2010 meeting, all members of the Stakeholder Group were contacted to provide FEI and FEVI with feedback. The goal was to ensure any concerns they may have with the practical application of the weighted average TRC or with the portfolio of proposed activity for Innovative Technologies have been brought forward and noted. The Companies did not receive any opposition from the Stakeholder Group through its request for feedback.

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[63] Based on BC emissions factors from Natural Resources Canada's GHGenius model 3.18 available at www.ghgenius.com
[64] Calculation based on US EPA Greenhouse Gas Equivalencies Calculator
[65] See page 114 of the EEC 2009 Annual Report

- On November 24, 2010, the EEC Stakeholder Group was further informed of the Commercial NGV Demonstration program through a 17-page presentation that focused exclusively on this topic. (Please see Appendix H for a copy of this presentation and a copy of the meeting minutes and attendees list).
- On March 15, 2011, the EEC Stakeholder Group was informed that the Companies are seeking confirmation from the Commission regarding the use of EEC funding for NGVs. (Please see Appendix H for a copy of this presentation and a copy of the EEC Stakeholder Group membership list). The timeline of regulatory proceedings,[66] as outlined in this section, was presented to the Group and several participants voiced their support for the Companies, and voiced their opinion that the Companies have been transparent on this matter and that the uncertainty should be removed as soon as possible to allow further funding to proceed.

The Companies asked those parties that spoke to this issue during the stakeholder group to provide a written comment for inclusion in this Report. FEI received letters in support of our approach to the funding approvals process from the following Stakeholder Groups:

a) BC Apartment Owners & Managers Association ("BCAOMA")
b) BC Sustainable Energy Association ("BCSEA")[67]
c) City of Vancouver ("COV")
d) Commercial Energy Consumers Association of BC ("CEC")
e) Fraser Basin Council ("Fraser Basin")

FEI has included these letters in Appendix F. Although all members of the EEC stakeholder group have been invited to comment, FEI has not received any specific letter of opposition to date.

Below, FEI has provided excerpts from these letters directed to FEI from Stakeholder Groups who attended these sessions:

From the BCAOMA letter:

> *The BCAOMA participated in stakeholder review sessions organized by FortisBC and had the opportunity to review and comment on the planned use of incentives to encourage the adoption of NGVs. During the November 24, 2010 session FortisBC provided a detailed presentation on the NGV program for BC, including the proposed use of EEC funding under the Innovative Technologies program. This presentation was favourably received by the stakeholder group. The BCAOMA believes that this consultation process meets the "Accountability Measures" defined in the Commission EEC Approval Decision G-36-09 and supports FortisBC's view that it has the necessary approvals to proceed with the NGV incentive program.*

[66] See Figure 10-1 in Section 10.2.3
[67] The BCSEA only attended the March 15, 2011 meeting. The other parties who provided letters attended both 2010 Stakeholder Group meetings.

From the BCSEA letter:

> *…as an active participant in the 2009 Energy Efficiency and Conservation Application of Terasen Gas, and a current member of FortisBC's EEC Stakeholder Group, the BC Sustainable Energy Association supports the use of FortisBC's EEC program to incent the purchase of heavy duty NGVs in place of diesel powered vehicles where cost effective, primarily because of the greenhouse gas emissions reductions benefits.*

From the COV letter:

> *We confirm that two stakeholder review sessions were held in 2010 (March and November) and that NGV programs were presented and discussed at these sessions. The City of Vancouver supports the continuation of the program to provide NGV incentives for heavy duty vehicle applications as adoption of NGVs in these markets provides GHG reductions and fuel cost savings to operators of NGVs.*

From the CEC letter:

> *The CEC would characterize the FEI approach with respect to its NGV initiatives as having been and continuing to be nothing but open and transparent. The CEC believes that FEI has worked diligently to build understanding and support for its NGV initiatives. The CEC has directly been involved in the regulatory processes, in which the CEC believed that FEI was being provided the CEC support and consent to both pursue these NGV initiatives and to fund these initiatives from EEC funds.*

From the Fraser Basin Council letter:

> *Through our involvement in the EEC Stakeholder group over the past two years, we have been informed of Fortis BC's ongoing plans to provide incentives for natural gas vehicles (NGVs) ... We are supportive of this effort by Fortis BC to provide incentives for NGV purchase...We also know that incentives are required to assist in overcoming the barrier of increased capital cost for NGVs.*

The Companies agree with the views expressed in these letters with respect to our approach to the funding approvals process.

10.2.3.3.3 Openness and Transparency of Innovative Technologies funding for NGVs in the 2009 EEC Annual Report and the 2010 Long Term Resource Plan

The Companies have been transparent about the use of Innovative Technologies Program Area funding for NGVs in two of its recent regulatory filings and proceedings.

Firstly, the 2009 EEC Annual Report, filed on March 31, 2010, states the Innovative Technologies Program Area includes NGVs. The suggested framework of the Innovative Technologies Program Area was described on Page 115:

> *TGI and TGVI restructured the existing portfolio list of Innovative Technologies to include Solar Thermal Hot Water, <u>NGV for Commercial Vehicles</u>, Hydronic and Combination Space Heating Systems, Residential GSHP and Commercial and Industrial GSHP Systems. <u>TGI and TGVI will treat NGV fuel switching from diesel as part of or normal course of EEC activities</u>. [Emphasis Added]*

Secondly, the 2010 Long Term Resource Plan ("LTRP"), filed on July 15, 2010, describes the Companies' plan to pursue NGV initiatives utilizing incentive funding from the Innovative Technologies Program Area.

The following is an excerpt from page 61 of the 2010 LTRP:

> *Since the Innovative Technologies portfolio was formulated, TGI has made progress with some of the technologies, particularly to support implementation of NGV technology.*
>
> *…TGI has initiated a pilot incentive program to encourage operators of heavy duty fleets such as garbage trucks and waste haulers to switch to natural gas from higher-carbon diesel. TGI has received expressions of interest from the City of Vancouver, City of Surrey, City of Port Coquitlam, and other third party partner* to use the EEC *funding to purchase new natural gas vehicles for garbage collection and transfer operations.*
>
> *Under the provisions of the pilot program, the fleet operators would be reimbursed for the incremental cost of the NGVs over conventional vehicles.*

No issues about the proposed use of EEC incentive funding for NGVs were raised in information requests filed in the LTRP.

As a result of the transparency of the Companies' NGV initiatives during 2009 and 2010, the support of stakeholders, and the fact that there were no issues raised during the LTRP information requests, the Companies were, with respect, surprised when the issue was raised by the Commission in the context of our Application for approval of the WM Agreement. The Companies are hopeful that the uncertainty can now be resolved.

10.2.4 SUMMARY

NGVs represent an important element of the Innovative Technologies Program Area, and the favourable TRC of NGV related incentives has contributed to a large measure to the favourable TRC of the overall Innovative Technologies Program Area portfolio. The Companies understand the Commission's desire to ensure that EEC funding is undertaken appropriately, and we have thus endeavoured to provide a more complete picture than was available to the Commission in the context of considering the Waste Management agreement as to why the Companies' initiatives are compliant with past Commission orders. Even if the Commission is unable to provide this confirmation, the Companies respectfully request that the Commission acknowledge the benefits of the Commercial NGV Demonstration program and the broad stakeholder support, and provide its concurrence for the Companies to proceed.

11 ENABLING ACTIVITIES

11.1 Introduction

Enabling Activities are activities that support the Companies' EEC program development and delivery. Although these activities do not have energy savings directly associated with them, they play a very important role because they provide resources common to the support and ultimately, the delivery, of all program area activities. Expenditures in these areas are part of the overall overhead of EEC program delivery, and are included at the portfolio level in the overall EEC portfolio TRC score.

In 2010, Enabling Activities fall into four major categories, including research and evaluation, Efficiency Partners program, codes and standards, and energy management funding.

11.1.1 RESEARCH AND EVALUATION

Two general areas of activity are included: market research and program evaluation. Market research provides invaluable background information used for planning and implementing effective programs, and program evaluation helps to measure the effectiveness of a particular program and/or initiative.

11.1.2 EFFICIENCY PARTNERS PROGRAM

The Companies identify efficiency partners as equipment manufacturers, service contractors, distributors, and retailers, and recognize the influence these various industry groups have with the end use residential and commercial customers who make energy efficiency decisions. Providing a targeted focus through investment in these industry groups is essential in order to consolidate and enhance existing service and supplier relationships, and through these efficiency partners, provide a delivery pathway for all EEC programs to customers.

The EEC Decision (Order G-36-09) did not approve the discrete Trade Relations program area funding that supports these activities as it was identified as a duplication of commercial and residential program delivery expenditure. The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the overall EEC TRC score. The EEC Stakeholder Group has not identified any objection to this approach.

11.1.3 CODES AND STANDARDS

Utilities play an important role in energy efficiency market transformation through support for the development of codes and standards. Government and regulating bodies are constantly seeking the participation and input of stakeholder groups, such as utilities, which have a unique understanding of energy supply and customer demand cycles, as well as the ability to support market transformation with financial incentives for efficient equipment and systems. The province's target levels and implementation of the *Greenhouse Gas Reduction Targets Act* are directly connected to effective market transformation in all EEC program areas. Utilities also play a role in keeping industry informed of developing codes and in alerting stakeholder groups of any unintended consequences that may arise out of proposed codes and standards.

11.1.4 ENERGY MANAGEMENT FUNDING

A key challenge to achieving customer adoption of DSM programs in the commercial sector has been a lack of resources at the customer end to source these opportunities and administer implementation of the appropriate energy efficiency measures. In response to this issue, the Companies have established human resources to assist customers with facilitating participation in their DSM programs. This includes the employment of energy solutions managers in each major service territory to focus on commercial customer outreach activities dedicated to increasing participation in the EEC programs. In addition, the Companies have developed a new major pilot initiative with the Energy Specialist program. For the Energy Specialist program, positions are created within large commercial customers that are funded by the Companies. The role of these Energy Specialist positions is to identify opportunities for DSM program participation for the customer as well as other projects that will result in more efficient use of natural gas.

11.2 2010 Enabling Activities

2010 Enabling Activities expenditures totalled $787,000 for FEI and $124,000 for FEVI. A bulk of these costs came from the Conservation Potential Review study, energy solutions managers, and the Energy Specialist program. Table 11-1 provides an overview of the 2010 expenditures for the Enabling Activities.

Table 11-1: 2010 Enabling Activities – Expenditures

Program	Description	Expenditure (000s)		
		FEI	FEVI	Total
Research and Evaluation	Market research and evaluation that support the overall EEC portfolio	$272	$68	$340
Efficiency Partners Program	Delivering EEC programs through B-ticket contractor companies	$55	$38	$93
Codes and Standards	Codes and standards related to EEC program areas	$15	$3	$18
Energy Management Funding	Providing assistance to customers for energy efficiency initiatives	$445	$15	$460
Total		$787	$124	$911

Further information on each of the four areas of the 2010 Enabling Activities is provided below.

11.2.1 RESEARCH AND EVALUATION

The Companies engage primarily in two activities within this category: market research and program evaluation. Both activities are important. Market research provides invaluable information used for planning and implementing effective programs, while program evaluation helps to measure the effectiveness of a particular program and/or initiative. This section provides a description of the research and evaluation activities undertaken in 2010.

11.2.1.1 Research Overview

Market research is defined as the systematic, objective collection and analysis of data about a particular target market, competition, and/or environment. It incorporates some form of data collection, which, in some instances, means primary research (i.e. collected directly from a respondent), while in others it can mean secondary research (i.e. collected from additional sources including related literature, the Internet, and media sources). It is important to conduct both primary and secondary research because together they allow the researchers to gain valuable insight about energy efficiency and conservation. Armed with this knowledge, the Companies are better able to develop, implement, and evaluate programs and activities.

11.2.1.2 Evaluation Overview

Evaluation of EEC programs and activities allows EEC staff to measure the effectiveness of the programs. Historically, the Companies have been conducting evaluation studies for DSM programs since the late 1990s. In general, program evaluations are designed in two stages. During the program design phase, the program evaluation concept is determined. The primary purpose of this is to understand the metrics for the evaluation and the data that will be required to understand those metrics, and to determine how much of this can be collected during program operation (i.e. as part of the incentive application). By doing this development prior to program launch, better quality data can be collected, potentially at a lower cost than if evaluation design was left until the time the evaluation was taking place. Once the program has operated for a sufficient period of time, an impact evaluation can be. In the past, the evaluations conducted on behalf of the Companies have been conducted by outside consultants who have been selected based on relevant experience and cost. Once selected, the consultant then further develops a detailed evaluation plan for review and discussion with the Companies. When the plan has been approved, the consultant typically begins the field research that includes, but is not limited to, field research (i.e. with participants and the relevant trade allies), billing analysis, and sub metering. Once field research is completed, the study moves into the analysis phase, which results in a final report developed by the consultant.

11.2.1.3 Research and Evaluation Studies Conducted In 2010

The various EEC program areas administer their own research and evaluation studies and apply those costs to their respective program area TRC benefit/cost test results. Descriptions and budgets for those studies have been captured in the respective program area sections in this Report. Those research and evaluation activities that are part of enabling activities and/or the overall EEC portfolio are described in this section. These expenditures are included in the overall portfolio-level EEC TRC benefit/cost test results. Each of the research and evaluation activities the Companies undertook in 2010 are listed in Table 11-2 below along with a reference to where their respective description and attributed costs can be found in the Report.

Table 11-2: 2010 EEC Research and Evaluation Activities

Study	Description	Expenditure (000s)	Reference
Tankless Water Heater Consumer Feedback	To gain insight about user experience of tankless water heaters to inform program development.	$18	Residential - 3.4.2.1
TLC Program Participant Survey	Provide customer feedback on program satisfaction and understand prevalence of furnace upgrades through servicing.	$15	Residential - 3.4.1.2
Condensing DHW Market Transformation	Develop market transformation strategy for the introduction of 0.80 EF DHW technologies.	$20	Residential - 3.4.3.2
Efficient Boiler Program Evaluation	Analysis of the natural gas savings of the Efficient Boiler program.	$43	Commercial - 4.4.2.1
On-farm Energy Assessments	Energy assessments at 25 separate sites to establish how agricultural producers use energy.	$55	Commercial - 4.4.4
MURB Remediation Study	A comprehensive rehabilitation study of problem strata buildings including an analysis of energy use and conservation strategies.	$10	Commercial - 4.4.3.6
EnerGuide Home Retrofit Study	Develop home performance overview of existing residential housing stock based on aggregate EnerGuide data from LiveSmart BC.	$20	Joint Initiatives - 7.4.2.1
Energy Modeling	Develop common archetype for utilities to develop economic models for LiveSmart BC offer development.	$3	Joint Initiatives - 7.4.2.1
Retrofit Energy Modelling in support of LiveSmart BC project	Common model for FEI and electric utilities for cost benefit analysis for LiveSmart BC offer development.	$5	Joint Initiatives - 7.4.2.1
Bill Insert and Bill Messaging Research Study	Determine readership level and understand if certain messages garner more attention from readers than other messages by our residential customers. Will finish study in 2011.	$10	Conservation Education and Outreach - 8.2.1.1
Contractor Qualitative Report	To gain insights around energy efficiency program awareness, preferred communication methods, and training needs.	$14	Enabling Activities - 11.2.1.3
Conservation Potential Review	Examines available technologies and determines their conservation potential.	$326	Enabling Activities - 11.2.1.3
Residential Retrofit Market Evaluation	Examines consumer awareness and brand awareness of retrofit rebate programs in the province of BC.	$19	2009 EEC Report Appendix D. P 50
Total		$558	

The costs associated with enabling activities and EEC portfolio level research studies are listed in Table 11-3 below. This is followed by a short description of each of these studies.

Table 11-3: 2010 Research and Evaluation Expenditures

Name of Study	Description	Expenditure (000s)		
		FEI	FEVI	Total
Contractor Qualitative Report	To gain insights around energy efficiency program awareness, preferred communication methods, and training needs.	$11	$3	$14
Conservation Potential Review	Examines available technologies and determines their conservation potential.	$261	$65	$326
Total		$272	$68	$340

11.2.1.4 Contractor Study

The Contractor study[68] (see Appendix F) was undertaken to enhance both the development of the Companies' EEC Efficiency Partners program and the LiveSmart BC program. This study was conducted in partnership with BC Hydro, FortisBC Inc., and the Ministry of Energy and Mines to identify the ideal communication channels for reaching contractors in BC, and to determine preferences regarding incentives and options in the Efficiency Partners program and the LiveSmart BC program. The study as a whole was budgeted at $40,000, with FortisBC Energy Inc. contributing $18,000, BC Hydro contributing $18,000, and FortisBC Inc. contributing $4,000. The specific objectives for this study fall into three main areas:

Training:

- To measure the level of awareness and understanding of Heating, Ventilating, and Air-Conditioning ("HVAC") contractors about energy efficiency ("EE") programs;
- Identify real and perceived barriers to promotion and participation in EE programs by contractors; and
- Determine the major challenges contractors have had in using the LiveSmart BC and other utility-led incentive programs.

EEC / LiveSmart BC incentive programs:

- To identify incentives and/or educational programs that will encourage contractors and tradespeople to participate in efficiency or utility-partner programs; and
- Use views and feedback from industry professionals for program development.

Communication channels:

- Identify the preferred communication channels for receiving information concerning EE programs for contractors and the trades;
- Determine preferred communication channels that will facilitate contractors and tradespeople in passing on the information to their customers;

[68] Contractor Study Qualitative Report, compiled by TNS for FortisBC Inc., BC Hydro, and Ministry of Energy and Mines.

- Determine which trade association's communications (i.e. newsletters) and/or trade publications are most accessible to contractors; and
- Determine the best avenues for advertising that will reach contractors.

The study involves two components: the qualitative component, which was completed in December 2010 (see Appendix F) and the quantitative component, with findings expected to be compiled by the end of March 2011. The final report is then delivered after the quantitative component is completed. The following observations surfaced from the initial qualitative phase of research. While they are not meant to serve as conclusive findings about all contractors, these observations provide a number of insights.

Contractors' Involvement in EE Incentive Programs

The qualitative work discovered that current EE incentive programs are not compelling enough for contractors to become fully engaged. Participants suggest that programs need to offer a greater value proposition for contractors to get involved. A key barrier to contractors' participation in EE incentive programs appears to be that the rewards do not compensate sufficiently for the time and energy invested – both the added un-billable time with the customer and extra time doing unpopular program application paperwork. Strategies that lower the time required to participate in a program will be very important to gaining contractors' full involvement. This could amount to simplified paperwork or simplified programs that are easier for contractors to learn and communicate.

A second key barrier to contractors' full involvement is their reluctance to promote something that is constantly changing for fear they will disclose the wrong information. Because of this, the contractors tend to avoid giving their input altogether, often advising customers to learn more from the program website directly. Given the importance of contractors' added opinions and advice, it seems creating a more stable, enduring program would have a positive impact on gaining contractors' involvement.

Customers' Involvement in EE Incentive Programs

Contractors feel current programs do not offer enough value to customers for the time required. They feel EE incentive programs *can* be of significant value to the customer if the programs offer enough of a financial incentive.

Contractors suggest effective EE incentive programs should specify a deadline that motivates action. Some suggest a reward in the form of money deducted from customers' monthly utility bills would be the most sought-after reward for an EE incentive program. They also feel the number of program requirements can discourage customer involvement, as well as the hassles associated with paperwork.

Communications

To learn about EE incentive programs, contractors would appreciate a forum where they could meet face-to-face with the Companies' program staff and ask questions. The easier these programs are to communicate, the more likely it is to gain contractors' involvement in promoting them. Time (in educating customers) is money to these contractors. Materials that expedite the communications process would be desired, such as brochures. Websites seem to be an expectation and serve as an important tool for contractors to redirect questions from customers. Contractors do have an advertising budget, although word of mouth is very strong in their industries.

Training and Upgrading

While some contractors would like opportunities to upgrade their skills, they seem opposed to training sessions that focus on marketing and sales of products or programs. Training programs that offer genuine and relevant skills would be of interest to some of the contractors.

Barriers to Contractor Participation

Many contractors feel these programs are not relevant to their businesses. For example, insulation professionals generally feel that once customers are ready for their service, they have already assessed these programs and included them in the work they request.

11.2.1.5 Conservation Potential Review Study

Please see Section 13 of this Report for a description and update on the Conservation Potential Review ("CPR") study.

11.2.2 EFFICIENCY PARTNERS PROGRAM

As described in Section 11.1.2, the Companies identify efficiency partners as being equipment manufacturers, service contractors, distributors, and retailers, and recognize the influence these various industry groups have with the end use residential and commercial customers who make energy efficiency decisions.

11.2.2.1 Background

In 2007, FEVI's Qualified Dealer program ("QDP") was reintroduced in the FEVI service territory, with an emphasis on further upgrading the quality of the participating gas contractors to ensure customers had access to highly qualified gas contractors. Contractors were required to re-register for the QDP that had new, more stringent guidelines such as: Better Business Bureau reference, BC Safety Authority ("BCSA") registration, business supplier referrals, customer referrals, business license, WorkSafeBC coverage, $2 million minimum liability insurance, and a business credit check.

Since the re-launch of the program in 2007, and until the increased EEC funding was approved in April 2009, limited resources were devoted to the QDP and essentially no incentive program offers for the FEVI market area were provided. There are currently only about 75 qualified dealers registered in the FEVI area out of a total market of approximately 350 gas contractors located in the FEVI service area. The marketplace has changed significantly since the QDP was first launched. Since the QDP was focused on FEVI, customers were looking primarily for a gas contractor (typically with a B-ticket) to convert them to natural gas and service their natural gas products. Today's energy consumer is looking for a wide range of services that include reliable information sources and manufacturers, installers, and service contractors that will provide energy efficiency recommendations for their entire house. The large number of gas contractors located in the Lower Mainland, the Interior, and on Vancouver Island represent an excellent opportunity for the Companies to promote a "whole-house" energy concept to customers. A whole-house system approach considers the interaction between the building site, regional climate, energy consumption habits, appliance efficiency, building envelope, and other elements or components in the home.

B-ticket gas contractors are one of the largest industry groups that influence end use customers. Domestic/commercial BCSA licensed B-ticket gasfitters install, test, maintain, and repair propane and/or natural gas lines, appliances, equipment, and accessories in residential and commercial premises up to 750,000 BTU. Industrial A-ticket gasfitters perform the same tasks as B-ticket gasfitters, plus an unlimited BTU range in industrial settings. They may work in new construction, or install systems in existing buildings that are being upgraded. C-ticket fitters are limited to residential gas appliance servicing only.

The Companies' overall objective for this market sector is to expand and rebrand the existing FEVI Qualified Dealer program (B-ticket contractors) in breadth and scope, and to open the new contractor program to include the Lower Mainland and the Interior.

While the Companies are starting with contractors as a first step in the Efficiency Partners initiative, the Efficiency Partners program will also eventually include efficiency service groups that have been previously excluded from the QDP. The Efficiency Partners program should be structured to be able to eventually include the following efficiency partners over time:

- Appliance installation contractor (A and B ticket);
- Gas appliance service groups (C ticket);
- Manufacturers and distributors;
- Big box retailers;
- Residential and commercial energy auditors;
- Weatherization services (draft proofers);
- Support groups (i.e. regulators and colleges); and
- Associations.

The rationale behind this expansion is that the current QDP has limited capabilities since the majority of the participating FEVI contractors are small "mom and pop" type of businesses. With an expansion to the Lower Mainland and Interior service areas, there is a concentration of much larger companies that will involve working with supplier and distribution groups. This will especially be true with big box stores. With the inclusion of a comprehensive group of service providers in the expanded Efficiency Partners program, customers will have access to a reliable network of highly qualified service providers with the ability to assist them with a wider range of efficiency services.

11.2.2.2 Efficiency Partners Program 2010 Activity Overview

In 2010, the Efficiency Partners program focus remained on continued evaluation and development of a new gas contractor program, reaching out to the gas contractor community through mail-outs and advertising communications, conducting focus groups, attending events and tradeshows, and maintaining the qualified dealer co-op advertising activities in the FEVI service area. Activity highlights of the Efficiency Partners program for 2010 are provided below.

11.2.2.3 Communication and Outreach Activity Milestones

Communication and outreach activities are essential in order to gain the support of, and deliver energy efficiency and conservation activities through the Companies' efficiency partners. These activities differ from those described in Section 8, which focus on general conservation and non-program specific communication that targets the general public. The following lists the communication and outreach activity milestones achieved in 2010:

- Contractor focus group sessions conducted in 2009 suggested the concept of establishing a quarterly newsletter containing value-added content of interest to the natural gas contractor community would be well received. With this feedback in mind, the first issue of the contractor newsletter was mailed in winter 2010 to over 2,400 contractor companies province-wide. As well, an incentive program update was mailed in fall 2010;
- Contractor focus group sessions held in FEI and FEVI service territories were completed in the first and second quarters of 2010, with insights collected used to support the development of new residential programs. Sessions were well attended, with feedback supporting the expanded program. These focus group sessions were in addition to the contractor study research discussed in Section 11.2.1.4. Below are some of the feedback highlights:
    - Contractors felt they did not have enough support and/or information about how changes to codes and standards would impact their business;
    - Concerns exist about the impact of new technologies (i.e. receiving products with no training support);

  - Contractors want to be 'in the know' about innovative technologies and understand how they might need to prepare to embrace these technologies;
  - Courses currently offered by colleges and associations are outdated;
  - Contractors would like to work more closely with the Companies in order to expedite requests for service connections; and
  - One of the main benefits of supporting an expansion of the contractor program was noted to be the contractor company listing on the Companies' website. Connecting customers with contractors who have been vetted through the contractor program lends credibility to these companies, and is therefore seen as a value-added benefit to the contractor.

- Three consultation workshops were conducted in partnership with the Ministry of Energy and Mines, FortisBC Inc., and BC Hydro, and included the greater contractor and energy audit communities in order gather insights and feedback to support program development for the 2011 iteration of LiveSmart BC. These sessions, held in Burnaby and Victoria, were conducted in the latter part of Q4. Below are some of the feedback highlights:
  - Need more focus on educating all stakeholders (i.e. homeowners, contractors, and suppliers) on the house-as-a-system ("HAAS") concept;
  - Improved communication (and more lead-time) on timing of changes to, and launches and closures of programs is required;
  - Energy advisors must take the lead and identify specific needs as there is very little contact, if any, between the contractor and the energy advisor. These two groups need to establish a closer relationship;
  - Contractors have more credibility in the eyes of homeowners than any other party so the Companies need them to be onside;
  - Manufacturers and distributors are key to communications with contractors; and
  - Contractor training is needed for ventilation and HAAS.
- Established direct contact and continued to develop relationships with energy efficiency equipment manufacturers and suppliers, and enhanced the Companies' involvement with contractor stakeholder groups such as associations and regulatory organizations. The Companies currently sit on the Thermal Environmental Comfort Association ("TECA") Board (non-voting member); and
- In 2010, association publications, magazines, and other promotional opportunities like web linking were identified in order to create an Efficiency Partners communication strategy for 2011. Trade publications and magazines provide an excellent opportunity to relay EEC initiatives and activities, including providing updates on activities related to the contractor program.

11.2.2.4 Co-op Advertising Activity

Participation in the existing Co-op Advertising program for gas contractors in FEVI remained steady throughout 2010. Development of the existing guidelines for expansion of the Co-op Advertising program to FEI continues, and will incorporate an increased focus on energy efficiency messaging. Related documents for the expanded Co-op Advertising program are in the final stages of review.

Expenditures in this area are part of the overall overhead of EEC program delivery and are funded at the portfolio level.

Table 11-4 identifies areas of operation and annual expenditures.

Table 11-4: 2010 Efficiency Partners Expenditures

Contractor Program	Expenditure ($000s)				
	Q1	Q2	Q3	Q4	Total
FEI	$12	$16	$10	$17	$55
FEVI	$15	$2	$2	$5	$24
FEVI Co-op Advertising	$1	$4	$3	$6	$14
Total	$28	$22	$15	$28	$93

11.2.3 CODES AND STANDARDS

11.2.3.1 Overview

Industry, regulating bodies, code development agencies, and user groups rely on the participation and input of stakeholder groups, such as utilities, that have a unique understanding of energy supply and customer demand cycles to assist in the development of codes and standards. The content and timing of code implementation directly affects market transformation in all program areas. Through the Efficiency Partners program, industry will be informed of developing codes and possible impacts to the marketplace.

It is important for the Companies to stay abreast of changing regulations; however, the Companies' *participation* in the development phase of regulation allows for more effective EEC program delivery and successful market transformation. This requires various levels of involvement. Codes and standards are established at a national level and adopted with or without changes at the federal and/or provincial level. The Companies' level of regulatory involvement is indicated by one of three involvement classifications:

Monitoring: To keep current with and informed about all existing and new codes and standards developments. These activities assist the Companies with the development of strategies to protect ratepayers and shareholders.

Stakeholder: For select provincial and federal code initiatives, the Companies participate at a *stakeholder* level, actively attending meetings and submitting written responses through the consultation phase. These activities, in conjunction with those of other key stakeholders, provide guidance to the final objectives.

Developing Regulations: Direct involvement with strategic steering committees, technical committees, and technical subcommittees for developing regulations and standards, as well as supporting studies and projects that provide information to help develop codes and standards. These activities directly enable standards development.

Table 11-5 identifies areas of operation and expenditures for 2010.

Table 11-5: 2010 Codes and Standards Expenditures

Codes and Standards	Expenditure ($000s)				
	Q1	Q2	Q3	Q4	Total
FEI	$10	$3	$3	-$1	$15
FEVI	$2	$0	$1	$0	$3
Total	$12	$3	$4	-$1	$18

Note: The surplus in FEI expenditures in Q4 represents an EnerGuide participation reimbursement of costs related to the Companies' involvement on the National EnerGuide Evaluation Committee.

It should be noted that EEC funds are only utilized to support the Companies' work on codes and standards in relation to areas that directly affect EEC programs and program development. Other work performed on codes and standards is covered by the Companies' Energy Products and Services department.

The following sections highlight codes and standards as they apply to EEC program areas for 2010 and are presented in the order of the Companies' involvement levels as outlined above - monitor, influence, and participate.

11.2.3.2 Standards and Company Involvement: Monitoring Level

Commercial Water Heater and Boiler Regulations

There were discussions for regulation changes to commercial water heater or commercial boiler standards to try to standardize units of energy. The United States uses American Standard units and official Canadian codes and standards use Scientific International (SI) units. Codes and standards are usually written with one set of units prescribed and the other set of units in brackets for information only. There are differences in how efficiency is calculated and there are differences in how energy input is reported. There was no resolution to this issue although there is more clarity since the discussions took place.

Residential Furnace Regulations

For new construction, gas furnaces manufactured on or after January 1 2008 must have a minimum Annual Fuel Utilization Efficiency ("AFUE") level of 90 percent. For existing dwelling retrofits, gas furnaces manufactured on or after December 31, 2009 must have a minimum

AFUE rating of 90 percent. As in-stock furnaces manufactured before the cut-off date can still be retailed, customers continue have a mid-efficiency choice.

Although these furnace regulations are in place, according to the Companies' 2008 Residential End Use Survey ("REUS"), almost 80 percent of the furnaces in the Companies' service territories were standard and mid-efficiency models. This represents a very significant area of potential for natural gas savings. Conventional DSM protocols only allow utilities to incent savings based on the regulated baseline. Also, utilities can only count savings beyond the regulated baseline that are generated as a result of the difference in efficiency between the in-situ technology and the replacement technology for those years that replacement is being moved up. For example, conventional DSM protocols would indicate that should a program incent a customer to early-replace an existing 80 percent efficient furnace five years before the end of its life with a 95 percent efficient furnace, the utility would only be able to count the energy savings from 80 percent to 95 percent efficiency for the five years of life remaining on the furnace. The rest of the savings would be calculated based on a change from 90 percent to 95 percent since 90 percent is the regulated minimum efficiency level. These conventional DSM protocols significantly limit a utility's ability to offer effective incentives on products with regulated minimum efficiency levels, as the energy savings on which incentives are based are small.

This is one of the reasons the Companies have under spent compared to approved expenditure levels: the residential furnace upgrade program had been a flagship program for FEI prior to the introduction of the 90 percent minimum efficiency standard. Yet limiting a utility's ability to offer effective incentives ignores marketplace realities. For example, data from the Companies' 2008 REUS indicates some customers are keeping their furnaces well beyond the end of equipment life – in some cases for 30 to 40 years. Not only do these older furnaces offer significant energy savings opportunities when replaced with higher efficiency models, they pose possible safety and human health hazards due to the potential for component failure that should be addressed, preferably through an incentive program to encourage customers to replace these older, inefficient units (i.e. a furnace scrap-it program). It is the Companies' intention to pursue such a program as part of the suite of EEC offerings for 2012 and 2013 that will be brought forward in the Revenue Requirements Application to be filed in May 2011.

Monitoring of trends in this area was considered a high priority as there were new technologies introduced that affected adoption, trades training, new installation requirements, and pricing. There were also unintended consequences from new venting requirements. For instance, since standard efficiency gas-fired furnaces and boilers usually share a metal vent with the gas-fired hot water tank, one unintended consequence of the new venting requirements was a trend towards electric hot water tanks in new construction. This is because new high efficiency condensing furnaces and boilers require a dedicated vent, quite often through the side wall of the building. This means the entire cost of a metal vent up through the roof is now associated with the gas-fired hot water tank only, instead of being shared by the furnace and hot water tank, which can discourage the installation of an energy efficient gas-fired hot water tank.

11.2.3.3 Standards and Company Involvement: Stakeholder Level

BC Building Codes for New Construction

In 2010, the Companies were involved at a stakeholder level in the development of the new provincial building codes. This required the development and analysis of multiple modelling scenarios to determine the impact of higher efficiency target levels. Modelling variables included fuel source, location, construction techniques, and materials. The stakeholder committee agreed to take the approach of concentrating on the thermal efficiency of the building enclosure. Industry will need to recognize the diversity of design and construction techniques that will be required for gas or electric applications.

The overall impact on construction costs to achieve higher efficiency ratings are under review. Once the building code is adopted, support for implementation will need to be provided. This will primarily involve educational support with industry stakeholders on energy specific changes to appliances, materials, and construction techniques.

Residential Boiler Regulations (Still in Proposal Stage)

Canada's energy efficiency regulations for residential boilers have remained unchanged since 1998. A regulation review is underway. When the new regulations are enacted, they will apply to any boiler manufactured after September 2010 and will mandate a Minimum Efficiency Performance Standard ("MEPS") of 82 percent with no standing pilot. Comments for review were accepted up to June 1, 2010. The Companies' involvement included written responses to NRCan's Office of Energy Efficiency ("OEE") during the consultation period.

The Companies will be monitoring the impact of these new regulations. Increases to appliance costs and technical challenges to retrofitting existing systems could have market impact. Technical challenges include possible increases to venting requirements and additional drainage requirements. Existing lower efficiency inventory appliances will still be available and will slow the integration of higher efficiency options into the marketplace. The customers for these appliances are homeowners for retrofit applications and homebuilders or developers for new residential construction.

Hearth Product Regulations

The Companies were involved with industry stakeholders to develop the EnerChoice top tier labelling system to help customers identify efficiency levels. The EnerChoice labelling system was introduced a few years ago, but the work of helping customers recognize the label and associated benefits is ongoing.

There is currently no regulation for minimum efficiency of hearth products; however, NRCan requires fireplaces to have a Fireplace Efficiency ("FE") rating label. Ratings for models currently available range from 20 percent to 70 percent FE.

Integration of some of these products into the ENERGY STAR® program would be a good start to raising awareness of the benefits of energy efficiency.

Solar Thermal Systems

The Companies have been involved with regulations pertaining to solar thermal installations and periphery areas like plumbing requirements, hybrid gas and solar systems, and monitoring technologies.

11.2.3.4 Standards and Company Involvement: Developing Regulations Level

Performance Standards

The Companies have staff actively participating on the Canadian Standards Association's ("CSA") "Energy Efficiency and Related Performance of Fuel-burning Appliances and Equipment" technical committee. This committee oversees the following performance standards: P.2 (residential gas-fired furnaces and boilers), P.3 (gas-fired storage water heaters), P.4 (fireplaces), P.5 (gas clothes dryers), P.6 (gas-fired pool heaters), P.7 (gas-fired instantaneous water heaters), P.8 (commercial gas-fired package furnaces), P.9 (combined space and water heating systems), P.10 (integrated mechanical systems for residential heating and ventilation), P.11 (gas-fired unit heaters), P.12 (gas-fired infra-red heaters), and the Plus 1200 compliance verification and rating system.

The CSA technical committee on Energy Efficiency and Related Performance of Fuel-burning Appliances and Equipment is a newly formed committee that had its inaugural meeting January 21, 2010 in Mississauga. The committee met again in person in June 2010 and communicated by teleconference and email throughout the year. The 2010 activities included:

- Merging the CSA P.2 (gas-fired residential furnaces and boilers) standard with the B212 (oil-fired residential furnace and boiler) standard;
- Merging the CSA P.3 (gas-fired storage water heaters) standard with the B211 (oil-fired storage water heater) standard;
- Submitting a proposal to open up the existing P.3 (gas-fired storage water heaters) standard to strengthen repeatability of the testing and ensure water draw patterns are more reflective of actual usage patterns; and
- Submitting a proposal to expand the PLUS 1200 document (guide to energy efficiency compliance, verification, and ratings for water heaters) to become a consensus document and include compliance testing for other key appliance categories.

Residential Domestic Hot Water Heater Regulations

Water heating represents about 20 percent of household energy use in Canada. Water heating will account for an ever increasing share of natural gas use as envelope construction, appliances, and HVAC continue to improve in efficiency, while conventional water heating equipment has changed little. The minimum efficiency of natural gas storage-type water heaters in BC is measured by an Energy Factor ("EF"), which is a volume adjusted factor. For the most common size, a 151 litre (40 US gal) tank, the minimum EF is 0.62 for water heaters manufactured after September 1, 2010. Customers will still have a choice until existing inventories are exhausted. This first tier of provincial change has not incurred adverse market effects. BC is moving alone without collaboration from federal agencies on this 0.62 efficiency level for residential gas-fired storage tanks.

There has been collaboration between NRCan and the BC Ministry of Energy and Mines along with the Canadian Gas Association ("CGA") and Canadian Institute of Plumbing and Heating ("CIPH") regarding future implementation of efficiency regulations. The different efficiency levels are often referred to as: Tier 1 0.62 EF, Tier 2 0.67 EF, and Tier 3 0.80 EF or condensing. These three tiers represent three different technologies needed to achieve the prescribed efficiency level for residential storage tanks. There are different efficiency levels and timelines for tankless units and storage units over 75,000 BTUH (British thermal units per hour) input. As described in the case of furnaces in Section 11.2.3.2 above, any changes to timelines or efficiency levels will impact the Companies' ability to offer effective incentives. Manufacturers have indicated they have concerns with the second and third tiers of the proposed water heater regulations. Some suppliers and distributors are not complying with Tier 1 requirements, citing supply problems. This is a provincial enforcement issue and highlights the hazards of regulation being out of step with supply. The second tier specifies an EF rating of 0.67 proposed for 2016 and the third tier is 0.80 or condensing technology proposed for 2020. The second tier would require retooling of equipment by manufacturers for a short time period and then retooling again for the third tier. There is uncertainty among manufacturers with regard to market share as the new tiers will require significant new investment with associated higher costs per unit production. Due to the short transition framework outlined by regulators, it is likely manufacturers will move to completely skip Tier 2. This will create additional problems for the gas industry as Tier 3 equipment can cost three times as much as Tier 1 equipment. This will affect new construction somewhat but will result in an energy shift to electric for retrofits. Utilities continue to try to bring stakeholders together to determine the appropriate market transformation plan.

A CGA partner 0.80 EF domestic hot water pilot program is currently in the development phase. Information on this pilot can be found in Section 3.

11.2.3.5 Summary

The Companies believe their codes and standards activities are aligned with and support the federal and provincial governments' energy and climate change objectives.

There are a number of product areas where regulations are connected to effective market development with the assistance of EEC programs including: commercial water heaters and boilers, residential furnaces, boilers, and domestic hot water heaters, hearth products, and BC building codes with particular attention to EnerGuide 80 ratings for houses and eventually net zero buildings in 2020. The Companies need to ensure codes are developed in conjunction with market dynamics and equipment manufacturers' ability to provide specified products in order to ensure their customers have appropriate choice in the marketplace.

If regulations are used to lead market change and force behavioural changes, instead of their traditional role of following the market curve and bringing along the slow starters, the Companies will lose their opportunity to help shift the marketplace with incentives and risk significant fuel switching. Residential hot water heater regulations and the 2011 implementation of the BC building codes, in particular, will continue to require a partnership with government and manufacturers to achieve a market transformation plan.

The Companies' EEC team will remain active with codes and standards committees as they pertain to EEC program and market development, and this will continue to be an important activity area.

11.2.4 ENERGY MANAGEMENT FUNDING

11.2.4.1 Overview

In the past, a major barrier to program adoption has been facilitation of equipment installation and application administration on the customer side. Potential program participants are often lost because they do not have the resources available to implement the measures required for program participation, nor the time to go through the application process. In these instances, the potential participant has the desire and financial means to implement the required measure but not the human resources to make it happen.

The Companies believe there is vast opportunity available for increased DSM program participation and energy efficiency implementation by providing resources to commercial customers to assist with program facilitation and energy efficiency projects. In 2010, three separate initiatives were launched to support this approach. This included hiring three EEC energy solutions managers, implementing a pilot program to fund the placement of energy specialists at key commercial customer accounts, and co-funding a community energy manager to support the community of Prince George. Expenditures for these initiatives in 2010 are listed in Table 11-6.

Table 11-6: 2010 Energy Management Funding – Expenditures

Name of Program/Initiative	Description	Expenditure (000s)		
		FEI	FEVI	Total
Energy Solutions Managers	Sales activities dedicated to increasing participation in the EEC programs	$204	$0	$204
Energy Specialist Program	Funding of energy management positions within select organizations	$241	$15	$256
Prince George Community Energy Manager	Funding of an energy management position for the community of Prince George	$0	$0	$0
Total		$445	$15	$460

11.2.4.2 Energy Solutions Managers

In spring 2010, the Companies recognized the need to proactively pursue energy efficiency and conservation opportunities directly with existing and potential commercial and institutional customers. In response to this need, the Companies took the initiative to develop three new roles within the sales department in May 2010 to focus specifically on energy efficiency and conservation. Recruitment began in June and all three positions were filled by December 2010. The three positions were stationed in the Lower Mainland, the Interior and on Vancouver Island. The position on Vancouver Island was the last one filled and, therefore, no expenditures appear in 2010 for FEVI. Approximately $200,000 was spent to fund these positions in 2010.

The EEC energy solutions managers ("ESM") are focused on sales activities dedicated to increasing participation in the EEC programs, including multifamily residential buildings and High-carbon Fuel Switching program areas. As part of their duties, the ESMs assist commercial customers with eligibility criteria and the requirements of applicable EEC programs, as well as support customers in the coordination and implementation of the necessary changes to equipment. These positions also offer valuable input to existing and future EEC programs based on customer feedback and market intelligence.

Each ESM has specific EEC program participation targets focused on commercial and institutional customers. They identify and work one-on-one with existing small and medium sized commercial customers that could benefit from current EEC programs. The ESMs also work closely with operations and other sales team members to uncover EEC opportunities such as potential high carbon fuel switching opportunities. They also provide support to the Companies' efficiency partners in the regions to maximize participation in the current EEC programs.

ESMs also attend and participate in trade shows and home shows, and deliver presentations to boards, municipal governments, service groups, and industry associations to promote the features and benefits of the current EEC programs. The regional energy solutions manager manages progress towards targets on a monthly basis.

11.2.4.3 Energy Specialist Program - PILOT

11.2.4.3.1 Energy Specialist Program Overview

Energy Specialist Program - Pilot	
Target Audience	Retrofit – Large Commercial and Institutional Customers
Duration	May 2010 - Dec 2011
Incentive	$60,000 per Energy Specialist
Partners	BC Hydro
Overview	
Background	BC Hydro and the Companies entered into a Memorandum of Understanding in July 2009 that established a set of principles for an enhanced coordinated approach to demand side management initiatives. This included plans to fund energy specialist positions with selected natural gas customers that already have an established BC Hydro-funded energy manager. Participants in the program were selected by reviewing the list of organizations that

	currently have a BC Hydro energy manager and determining, through a consultative process with BC Hydro and the Companies' commercial account managers, which would have the best chance at bringing in new energy efficiency projects.
Description	The energy specialist reports to and supports the energy manager on holistic energy reduction projects while also focusing on identifying opportunities to use natural gas more efficiently. Funded as an enabling program, a key priority for the energy specialist is to identify opportunities for their organization to participate in the Companies' EEC programs. Energy specialist positions are funded by the Companies up to $60,000 for a period of one year. Energy specialists are required to submit a quarterly report outlining their projects that are completed, in progress, and planned. To qualify to be an energy specialist, candidates for these positions must be either a graduate from the BCIT Sustainable Energy Management Associate Certificate program or have a master's degree in Clean Energy from UBC.
Goals	• Increase participation in the Companies' EEC programs. • Develop and execute other projects that result in natural gas savings. • Work with the energy manager on projects that result in holistic energy savings.
Implementation	
Administration	Administered internally within the Companies' EEC group.
Communications	As a pilot initiative, the energy specialist program is not being actively promoted at this time.
Evaluation Strategy	This pilot program will be evaluated in Q3 2011 to determine its overall viability, assess program delivery and reporting mechanisms, and full program roll-out options. This evaluation will be conducted through analysis of energy specialists' quarterly reports and qualitative feedback from participating organizations and the Companies' account managers.

11.2.4.3.2 2010 Energy Specialist Program Results

Table 11-7: 2010 Energy Specialist Program Expenditures

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	13	$240	$1	N/A	N/A	N/A	N/A
FEVI	1	$15	$0	N/A	N/A	N/A	N/A
Total	14	$255	$1	N/A	N/A	N/A	N/A

Twenty separate organizations were approved by the Companies to hire energy specialists in 2010 as part of the pilot launch of the Energy Specialist program. Of these organizations, six were still working through the hiring process at the end of 2010 to fill their respective energy specialist positions.

To date, anecdotal feedback on the program from the participating organizations has been very positive. Participating organizations have been able to make a lot of progress on their energy efficiency projects with the addition of the energy specialist position. In addition, there have been observed efficiencies in pairing the energy specialist with the BC Hydro-funded energy manager in that the energy specialist has been able to step in immediately to begin working on projects and reporting results based on the models and tools already established by the BC Hydro-funded energy manager.

11.2.4.4 Prince George Community Energy Manager – PILOT

11.2.4.4.1 <u>Prince George Community Energy Manager Overview</u>

Prince George Community Energy Manager - Pilot	
Target Audience	Retrofit and New Construction - Prince George Community (all types of customers)
Duration	Nov 2010 - Nov 2011
Incentive	$25,000
Partners	BC Hydro, NRCan
Overview	
Background	After discussions with the City of Prince George in mid-2010, the Companies agreed to co-fund a community energy manager to focus on the community of Prince George. BC Hydro has funded similar positions in the past, which helped establish the framework for this position. The City of Prince George has shown a keen commitment to promoting energy efficiency and green initiatives for its community. This also contributed to the decision to select this opportunity as a pilot program for funding a community energy manager. Establishing the funding agreement and identifying a suitable candidate took several months but was finalized in November 2010.
Description	Working for the City of Prince George and reporting to the environment manager, the Prince George community energy manager (“CEM”) is responsible for identifying and facilitating the implementation of energy efficiency opportunities for the community of Prince George in order to reduce grid-supplied energy use and fossil fuels use, including natural gas, and to meet target GHG emissions reductions by 2012. The Companies have split the funding of this position with BC Hydro and NRCan. The Companies’ contribution is in the amount of $25,000 for one year. Funded as an enabling program, a key priority for the CEM is to identify opportunities for natural gas customers in Prince George to participate in the Companies’ DSM programs. The CEM is required to submit a quarterly report outlining their natural gas related projects that are completed, in progress, and planned.
Goals	The following deliverables from the CEM have been requested by the Companies: • Promote the Companies’ energy efficiency programs, information, and incentives;

	• Work to increase the Companies' program participation by residents and businesses in Prince George; and • Explore and develop projects that result in more efficient use of natural gas in the Prince George area.
Implementation	
Administration	Administered internally within the Companies' EEC group.
Communications	As a pilot initiative, the community energy manager program is not being actively promoted at this time.
Evaluation Strategy	At the time of writing this report, the plan for this pilot program is to fund only this one CEM position until the end of the initial one year term. Towards the end of this term, the pilot program will be evaluated to determine its overall viability, the benefits of extending this position to a second year, and the possibility of opening it up to include funding for CEMs in other communities. This evaluation will be conducted through an analysis of the CEM's quarterly reports.

11.2.4.4.2 2010 Prince George Community Energy Manager Results

The Prince George CEM was hired in November 2010. While the CEM position started in November 2010, the first funding payment is not due until February 2011; therefore, no dollars are shown to be committed to this pilot program in 2010. In November and December of 2010, the CEM established priorities for the position, worked to become familiar with the Prince George market, and began work on a strategic energy management plan.

11.2.5 SUMMARY

Enabling Activities provide important support for effective EEC program development, delivery, and evaluation. Most EEC programs work on the principal of market transformation with eventual mandate by regulation as the end goal.

Research and evaluation provides the information required to create a market development plan. The Efficiency Partners program aids in efficient delivery of EEC programs and provides the vital industry feedback for program adjustments. Regulation target levels and implementation timeframes require guidance from industry stakeholders.

Given the aggressive provincial GHG emissions reduction targets, participation on the various codes and standards committees is critical. Poorly constructed or timed regulations could result in a void of products and services and disrupt market transformation processes. Unsuccessful market area transformation could result in an unbalanced shift to one energy source, creating a supply and demand problem that could in turn result in rate increases for customers.

Energy management funding enables customers, who might otherwise not enter into energy efficiency and conservation projects due to lack of resources, to get involved in initiatives that will decrease their energy consumption.

The Companies believe the results of Enabling Activities in 2010 demonstrate their value and intend to continue to refine and improve such activities in 2011.

11.3 2011 Planned Enabling Activities

As discussed in Section 11.1, in 2010 the Companies pursued Enabling Activities in support of broader EEC activities and programs. These activities fall into four major categories: research and evaluation, Efficiency Partners program, codes and standards, and energy management funding. In 2011 these four areas of focus will remain the same and the Companies will increase and broaden their planned activities in each.

The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the overall portfolio level expenditures.

As the Companies' EEC initiative continues to expand through 2011 and beyond, the efficiency partners and codes and standards areas have the potential to consume significant resources. As these areas develop, it may be necessary to reassess the need to establish a separate program area for these activities in the future, with their own budgets.

Table 11-8 below shows the budgeted amount for 2011 Enabling Activities. Note, however, that not all research and evaluation studies have been determined for 2011 and so the total planned expenditures for this area are yet to be determined.

Table 11-8: 2011 Enabling Activities - Forecast Expenditures

Program	Description	Expenditure ($000s)		
		FEI	FEVI	Total
Research and Evaluation*	Market research and evaluation that support the overall EEC portfolio	$190	$48	$238
Efficiency Partners Program	Delivering EEC programs through B-ticket contractor companies	$317	$105	$422
Codes and Standards	Codes and standards related to EEC program areas	$60	$15	$75
Energy Management	Providing assistance to customers for energy efficiency initiatives	$1,391	$293	$1,684
Total		$1,958	$461	$2,419

* Only includes the CPR and Contractor studies. Does not include any additional research studies that may be undertaken in 2011.

Further information on each of the four areas of the 2011 Enabling Activities is listed below.

11.3.1 RESEARCH AND EVALUATION

11.3.1.1 2011 Overview

Each of the research and evaluation activities the Companies plan to undertake in 2011 are listed in Table 11-9 below, along with a reference as to where their respective description and attributed costs can be found in this report.

Table 11-9: 2011 EEC Research and Evaluation Activities

Study	Description	Expenditure (000s)	Reference
Getting to EnerGuide 80 and Beyond - New Home Construction	Determine energy savings, costs, and lifecycle costs for natural gas and electic heated homes for EnerGuide 80 through to EnerGuide 86 (this study is jointly funded by BC Hydro).	$34	Residential - 3.4.3.2
EnerChoice Efficient Fireplace Brand Awareness	Determine awareness of EnerChoice efficient fireplaces in both consumers and dealers to inform program development and outreach.	$15	Residential - 3.4.2.2
On-farm Energy Assessments	Energy assessments at an additional 25 separate sites to establish how agricultural producers use energy.	$28	Commercial - 4.4.4
MURB Remediation Study	A comprehensive rehabilitation study of problem strata buildings including an analysis of energy use and conservation strategies.	$10	Commercial - 4.4.3.6
Field verification of Hot 2000 base modeling and with consumption data	Compare energy savings estimates in Hot 2000 to consumption data to inform NRCan as to more accurate savings estimates for BC (gas and electric).	$25	Joint Initiatives - 7.4.2.1
Standard Operating Conditions for Hot 2000 Modeling for BC	Review EnerGuide Standard Operating Conditions (SOC) and provide recommendations to provide consistency across utilities and governments.	$3	Joint Initiatives - 7.4.2.1
Bill Insert and Bill Messaging Research Study	Determine readership level and understand if certain messages garner more attention from readers than other messages by our residential customers. Study began in 2010 and will be completed in 2011.	$12	Conservation Education and Outreach - 8.2.1.1
EEC Event Tracking	To determine the success of the overall approach (event attendance and/or sports team partnerships along with an online contest) for raising awareness of energy conservation.	$15	Conservation Education and Outreach - 8.3.1.1
EEC Long Term Tracking	To track awareness levels for EEC messaging, message retention, and programs overtime among the residential and general public audience.	$60	Conservation Education and Outreach - 8.3.1.1
Geoexchange Energy Performance Study	The Companies have committed EEC funds for a geoexchange energy performance evaluation project initiated through Geoexchange BC. The goal is to evaluate the energy savings attributable to installed geoexchange systems in MURBs and commercial and institutional buildings.	$12	Innovative Technologies - 10.4.1.2
CEATI Gas Utilization Working Group Membership	Participate in this working group to investigate the market potential and energy savings for different market ready technologies and collaborate with utilities and stakeholders on potential studies, pilots, and demonstration projects.	$4	Innovative Technologies - 10.4.1.2
Westhouse Demonstration Project	The project is a collaboration between City of Vancouver, Simon Fraser University, and FEI to demonstrate alternative energy in high visibility collaboration and to gain information on operation and energy performance of the solar thermal system.	$12	Innovative Technologies - 10.4.1.2
Contractor Qualitative Report	To gain insights around energy efficiency program awareness, preferred communication methods, and training needs.	$4	Enabling Activities - 11.2.1.3
Conservation Potential Review	Examines available technologies and determines their conservation potential.	$234	Enabling Activities - 11.2.1.3
Total		$468	

Beyond completion of the Contractor study and the Conservation Potential Review study, research activities at the EEC portfolio level have not been planned out yet for the year. Therefore, the total dollar value listed in Table 11-9 only includes these two studies and does not take into account any other studies that may be required in 2011.

As discussed in Section 11.2.1.4, the Contractor study involves two components: the qualitative component completed in December 2010 (refer to Appendix F to see the report) and the quantitative component, with findings expected to be compiled by the end of March 2011 and the final report delivered thereafter. The Conservation Potential Review study is scheduled to be completed at the end of March 2011. Please refer to Section 13 for more information on this study and the expected results.

Table 11-10 outlines expected research and evaluation expenditures for 2011.

Table 11-10: 2011 Research and Evaluation - Forecast Expenditures

Name of Study	Description	Expenditure (000s)		
		FEI	FEVI	Total
Contractor Qualitative Report	To gain insights around energy efficiency program awareness, preferred communication methods, and training needs.	$3	$1	$4
Conservation Potential Review	Examines available technologies and determines their conservation potential.	$187	$47	$234
Additional Studies		TBD	TBD	TBD
Total*		$190	$48	$238

* Total does not include any additional research studies that may be undertaken in 2011.

11.3.2 EFFICIENCY PARTNERS PROGRAM

11.3.2.1 Overview and Highlights

The 2010 Efficiency Partners program development highlights noted in Section 11.2.2 form a solid foundation from which to further develop this initiative in 2011. Strong uptake of EEC programs through the course of 2011 will require strong Efficiency Partner group support. It is important for industry stakeholders with end-use customer influence to be aligned with the Companies' stance of promoting high efficiency appliances, due to their direct customer contact.

To promote this support, the Companies will broaden their Efficiency Partners program in 2011 beginning with natural gas service providers through the expanded contractor program. As suggested in Section 11.2.2, while the Companies are starting with contractors as a first step in the partner's initiative, the Efficiency Partners program will also eventually include efficiency service groups like suppliers, distributors, and so on. Highlights of the planned 2011 Efficiency Partners program activities are as follows:

- Roll out of the expanded Contractor program to all service territories;
- Province-wide registration drives to encourage participation in the Contractor program to be held during the latter part of the second quarter. The sessions will include an

educational component with guest speaker (i.e. new water heater technology, emerging technologies, and BCSA permitting requirements);

- Focus on outreach through the further development and enhancement of the Companies' website (i.e. customer and efficiency partner portals), developing promotional materials for both customers and efficiency partners, participating in third-party communications through association and stakeholder newsletters, and participating in association events and tradeshows;
- Use Contractor study research findings to guide the development of training opportunities for contractors and work with trade associations to deliver these opportunities; and
- Develop and launch the Contractor program sub-brand name and logo across all service territories.

As noted in section 11.1.2, Order No. G-36-09 did not approve the discrete trade relations budget area put forward as it was considered by the Commission to be a duplication of commercial and residential program delivery expenditure. The expenditures in this area are part of the overall overhead of EEC program delivery and are included in the costs for the overall EEC portfolio.

Table 11-11 is an estimate of the expenditures required to develop and maintain the 2011 Efficiency Partners program.

Table 11-11: 2011 Efficiency Partners Program – Forecast Expenditures

Efficiency Partners Program	Expenditure ($000s)		
	FEI	FEVI	Total
Registration/application administration (Contractor program)	$22	$6	$28
Promotion, brochures, and trade magazine ads	$18	$5	$23
Conferences and trade shows	$12	$3	$15
Quarterly newsletters	$19	$5	$24
Efficiency workshops/training	$64	$16	$80
Website development	$40	$10	$50
Co-op advertising	$20	$30	$50
Program development expenses	$48	$12	$60
Program development labour	$74	$18	$92
Total	$317	$105	$422

11.3.2.2 Expanded Contractor Program Roll Out

Focus during the first and second quarters of 2011 will be to roll out the expanded Contractor program, as described in section 11.3.2.1, to all service territories. There are over 2,400 natural gas contractor companies registered with the BCSA. It is anticipated that registration activity will continue through 2011 and beyond. Registration drives are planned in the latter part of the second quarter to promote the Contractor program and will continue throughout the year.

11.3.2.3 Focus on Outreach and Communication

Relaying the benefits of the Contractor program to both the contractor community and customers seeking products and services from contractor companies is key to the success of the expanded program; therefore, this will be the focus for the latter part of Q2 and will continue through to the end of the year. The continued development and enhancement of the Companies' website will offer one of the major benefits to contractor companies, namely, to have their business listed on the website. For customers, the benefit is the ability to use the website to seek out a local contractor that offers the products and services they require. The contractor portal will include information related to the Companies' EEC initiatives and activities, training opportunities, emerging technical information related to codes and standards, links to the Contractor program application, co-op advertising reimbursement forms, and related terms and conditions, and links to the contractor newsletters. The customer portal will include a listing of the Companies' member contractor companies. Customers seeking a contractor company will be able to search by various fields, including geographic area and services required. Contractor listings will include affiliations, training, and Better Business Bureau accreditation, with a description of each and link back to the organization should the customer wish to learn more about these affiliations. Value-added tips like 'how to find a qualified contractor' and knowing what questions to ask when hiring a contractor will also be featured.

Additional activities to promote the Contractor program include developing promotional materials to support participation in events and tradeshows, placing ads in trade publications, magazines, and e-newsletters, participating in stakeholder events like lunch and learn sessions, and exploring speaking opportunities through associations.

The Companies recognize that direct contact with gas contractor companies, manufacturers, suppliers, and other service groups connected to the gas industry (i.e. home auditors and inspectors) is essential. These stakeholder groups must be educated about the benefits of high efficiency equipment and their concerns about availability and complexity need to be alleviated.

11.3.2.4 Training Development and Promotion

Understanding the training needs of the contractor community will be achieved through research findings that will be available in the first quarter of the year. Based on these findings, the focus for the third and fourth quarters of the year will be on development training opportunities, identifying educational partners, and determining delivery options. At this time, anecdotal evidence suggests the following are training areas to explore:

- How to perform heat-loss calculations to determine optimal sizing of boilers (in particular for commercial applications);
- Taking a whole-home or HAAS approach to identifying energy efficiency opportunities;

- Emerging EEC technologies;
- Understanding the impact of codes and regulations (i.e. release of the new provincial building code in the latter part of 2011);
- Customer service/sales 101; and
- Managing business and finance.

Consulting with experts in these areas and partnering with associations to deliver training opportunities to the contractor community will require a consolidated effort among stakeholders in order to provide the most cost efficient and equitable access to programs for all contractors.

11.3.2.5 Co-op Advertising and Sub-brand

Gas contractors currently registered in the Qualified Dealer program in FEVI will continue to use the existing logo when participating in the Co-op Advertising program through Q1 and Q2. The co-op advertising benefit of the Contractor program will be made available to all remaining service territories in Q3, when it is expected a new contractor sub-brand name and logo will be launched.

The following outlines co-op advertising parameters:

- Gas contractors may receive a reimbursement of up to 50% for an approved marketing piece with a maximum reimbursement of $5,000 per program year, per company;
- Funding is limited and will be dispersed on a first-come, first-serve basis;
- All advertising must be pre-approved by the Companies;
- Advertising must include the program logo;
- Advertising must promote the use of natural gas equipment only; and
- The Companies may require advertising to include messaging around energy efficiency and conservation.

Co-op advertising dollars may be available for the following media:

- Print (excluding print ads in the Yellow Pages);
- Radio;
- Direct mail;
- In-store displays; and
- Other marketing pieces approved by the Companies.

Increased levels of participation in the Co-op Advertising program are expected in the FEI territory as the number of participants increase in the new Contractor program in the third and fourth quarter of 2011 and beyond. The participation levels in FEVI are expected to increase as well, as contractor companies in this region join the new Contractor program.

Table 11-12 below identifies projected quarterly estimates for the co-op advertising reimbursement activity for 2011.

Table 11-12: 2011 Co-op Advertising Reimbursement Estimates

Co-op Advertising	Expenditure ($000s)				
	Q1	Q2	Q3	Q4	Total
FEI	$0	$0	$6	$14	$20
FEVI	$4	$9	$8	$9	$30
Total	$4	$9	$14	$23	$50

11.3.3 CODES AND STANDARDS

11.3.3.1 Overview

Industry, regulating bodies, code development agencies, and user groups rely on the participation and input of stakeholder groups, such as utilities, which have a unique understanding of energy supply and customer demand cycles, to assist in the development of codes and standards. The content and timing of code implementation directly effects market transformation in all program areas. Through the EEC Contractor program, industry will be informed of developing codes and possible impacts to the marketplace.

Keeping current is important, however, the Companies' participation in the development phase of regulations allows for more effective EEC program delivery and successful DSM market transformation. This requires various levels of involvement. Codes and standards are established at a national level and adopted with or without changes at the federal and/or provincial level. The Companies' level of regulatory involvement is indicated by one of three involvement classifications: monitoring, stakeholder engagement, and developing regulations

Table 11-13 below identifies estimated expenditures by activity projected for 2011.

Table 11-13: 2011 Codes and Standards Expenditure Estimates

Code area	Expenditure ($000s)		
	FEI (20%)	FEVI (80%)	Budget
Building Code New Construction	$4.6	$18.4	$23.0
Performance Standards	$2.0	$8.0	$10.0
Commercial Boilers and Water Heaters	$0.8	$3.2	$4.0
Residential Boilers, Furnaces, and DHW	$2.2	$8.8	$11.0
Hearth Products	$0.2	$0.8	$1.0
Solar Thermal Systems	$1.6	$6.4	$8.0
*New initiatives for 2011	$3.6	$14.4	$18.0
Total	$15.0	$60.0	$75.0
* Thermal Metering, NGV, Solar			

The sections that follow offer highlights for new codes and standards as they apply to EEC program areas for 2011 and are presented in order of the Companies' involvement levels, including: monitoring, influencing, and participating. The codes and standards activities that were undertaken in 2010 will continue in 2011, along with new identified subject areas.

11.3.3.2 Codes and Standards, and Company Involvement: Monitoring Level

Residential Furnace Regulations

The Companies had stakeholder involvement in the adoption of this standard and will now monitor any changes that may come out of implementation. Change-out of existing standard and mid-efficiency furnaces would result in large efficiency gains and a Furnace Scrap-it program (see Section 3) is being evaluated to capture these potential gains.

11.3.3.3 Codes and Standards, and Company Involvement: Stakeholder Level

Towards Net Zero Buildings in BC for 2020 (Future Code)

The BC Government has announced it is moving toward a net zero energy or net zero energy capable (the Passive House standard) construction code by 2020. The Companies participate in both the EnerGuide 80 and Net Zero committees.

At a minimum, a net zero home supplies to the power grid an amount equal to the total amount of energy consumed. It combines the amount of energy (electricity and, if applicable, natural gas) used to operate a home and the amount needed to provide an equal amount of self-generated energy back to the grid, when possible. A passive house generates and stores all the energy it requires without connecting to any utility supply. The implementation of a net zero energy capable construction code by 2020 will require the development of an implementation road map to identify the barriers and develop solutions with all stakeholder groups. At this point in the development of the code, the Companies are participating at a stakeholder level.

Thermal Metering

Thermal metering is a technique that measures changes in temperature and the flow rate of a fluid and uses a calculation to derive the amount of thermal energy delivered by that fluid. Thermal metering will be required for district energy systems and solar thermal projects. This metering will be required for accurate billing and should not be confused with metering for pilot studies. To date, Measurement Canada has not recognized any technology for this purpose. Many of these technologies exist in Europe and a task force is being assembled by the CGA to work towards a Canadian solution to this challenge. Many of the existing EEC programs and innovative technologies under assessment will require this type of metering. EEC is planning to participate in this stakeholder project.

11.3.3.4 Codes and Standards, and Company Involvement: Developing Regulations Level

Building Code EnerGuide Rating (Part 9)

The provincial government continues to work toward the implementation of a new BC Building Code to take effect in late 2011. The current rating of 77 and the new 80 rating are stepping stones toward a net zero level set for 2020, and are described above in Section 11.3.3.3. The Province of British Columbia is updating the energy efficiency requirements in the Energy and Water Efficiency section (Part 10) of the BC Building Code for residential buildings.

A study involving the Companies and a number of industry partners was started in 2009 to determine potential combinations of overall building envelope thermal requirements, air tightness, and equipment efficiency in order to meet EnerGuide 80. A number of base cases were modeled using the NRCan Hot 2000 program, using the following variations:

- Various archetypes of detached homes and row homes;
- Primary space heating system: electric, natural gas (water heating is assumed to match); and
- Climate zones in BC: Southern Coastal, Southern Interior, and Northern Interior.

The modeling study was completed in 2010. A stakeholder committee was created to develop the guidelines for changes to the BC Building Code based on the results of the study and input from the representing groups. The Provincial Government is now assessing the impact of these proposals on industry. A new construction program to move industry to an EnerGuide 80 standard is in development and details about this program can be found in Section 11.3.3.3.

Ventilation

The Company is involved with a large collaborative study looking at the effects of building remediation on energy usage and ventilation in multifamily buildings. The Companies expect to be involved with ventilation standards for multifamily residential buildings in the new BC Building Code.

11.3.3.5 Summary

There are a number of product areas where regulations are connected to EEC programs, including: BC Building Code with particular attention to EnerGuide 80 ratings for houses and eventually net zero buildings in 2020, performance standards, commercial water heaters and boilers, residential furnaces, boilers, and domestic hot water heaters, hearth products, solar thermal systems, thermal metering, liquefied natural gas, compressed natural gas, and ventilation

EEC will remain active with codes and standards committees as they pertain to EEC program and market development, and this will continue to be an important activity area. The 2011 implementation of the new BC Building Code for new home construction with EnerGuide 80 efficiency targets will be of particular interest in the near term. The planned budget for this area of activity for 2011 is estimated at $75,000, which is based on a time commitment equivalent to two thirds of a full time position.

11.3.4 ENERGY MANAGEMENT FUNDING

11.3.4.1 Overview

In 2011, the Companies plan to continue with their energy management funding activities that were launched in 2010. A full year of activity in these areas will necessarily result in increased expenditures compared to 2010; however, no new energy management activities are currently planned beyond what was launched in 2010. The Energy Specialist program and the Prince George community energy manager position will be evaluated in 2011 to determine if funding in these areas should be continued and if similar funding should be extended to other customers and communities. Table 11-14 displays planned expenditures for energy management funding in 2011.

Table 11-14: 2011 Energy Management Funding – Forecast Expenditures

Name of Program/Initiative	Description	Expenditure (000s)		
		FEI	FEVI	Total
Energy Solutions Managers	Sales activities dedicated to increasing participation in the EEC programs.	$225	$113	$338
Energy Specialist Program	Funding of energy management positions within select organizations.	$1,141	$180	$1,321
Prince George Community Energy Manager	Funding of an energy management position for the community of Prince George.	$25	$0	$25
Total		$1,391	$293	$1,684

11.3.4.2 Energy Solutions Managers

The three ESM positions will continue as is through 2011. It is estimated that $340,000 will be spent to fund these positions in 2011.

11.3.4.3 Energy Specialist Program – PILOT

By early 2011, the Companies expect all approved pilot program participants to have hired their respective energy specialists. The forecast expenditures listed in Table 11-15 assume they will all be employed for the duration of 2011. This pilot program will be evaluated in Q3 2011 to determine its overall viability and to assess program delivery and reporting mechanisms and full program roll out options. This evaluation will be conducted through analysis of energy specialists' quarterly reports and qualitative feedback from participating organizations and the Companies' account managers.

Table 11-15: 2011 Energy Specialist Program Forecast

Utility	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	Free Rider Rate	TRC
FEI	19	$1,140	$1	N/A	N/A	N/A	N/A
FEVI	3	$180	$0	N/A	N/A	N/A	N/A
Total	22	$1,320	$1	N/A	N/A	N/A	N/A

11.3.4.4 Prince George Community Energy Manager – PILOT

The full $25,000 funding commitment to the Prince George community energy manager ("CEM") position will be incurred in 2011. As of the writing of this report, the plan for this pilot program is to only fund this one CEM position until the end of the initial one year term. Towards the end of this term, the pilot program will be evaluated to determine its overall viability and the benefits to extending this position to a second year and opening it up to include funding for CEMs in other communities. This evaluation will be conducted through the analysis of the CEM's quarterly reports.

11.3.5 ENERGY EFFICIENCY FINANCING

Background

The Ministry of Energy and Mines has been encouraging BC Hydro and the FortisBC Utilities to jointly implement an energy efficiency financing program that would overcome the "first cost" barrier to existing energy efficiency incentive programs. The Ministry of Energy and Mines has created a working group that also includes other relevant ministries, the BCUC, and the City of Vancouver to explore different energy efficiency financing program options. There are a number of energy efficiency incentive programs currently offered to BC homeowners by the provincial government and energy utilities. Most of these programs require homeowners to pay for energy efficiency improvements up front, and then the homeowner receives a grant or rebate for a portion of the energy efficiency improvement cost. While these programs have been well subscribed, the requirement for homeowners to pay up front for energy efficiency improvements represents a significant participation barrier for many households, particularly given that energy efficiency upgrades are a lower priority investment and viewed more as a necessity in the event of an equipment breakdown or repairs than traditional cosmetic and expansion projects. Many homeowners either do not have the financial resources or access to financing to pay the upfront cost for the energy efficiency improvements or feel the hassles of working with their bank outweigh their desire to become more efficient. To overcome this barrier, the Ministry of Energy and Mines views the utilities as key partners in developing the financing program and believes energy efficiency financing will be a flagship program to meet the aggressive GHG emissions reduction targets set in legislation and promote a culture of conservation in BC.

Financing Options:

In October 2010, the Ministry of Energy and Mines requested that the utilities submit a joint proposal for a pilot energy efficiency financing program. While various financial models and program design principles were reviewed, the Ministry of Energy and Mines has strongly favoured the “Pay As You Save”, or PAYS, model. The PAYS model is designed around the creation of a utility-owned entity that would:

- Borrow funds from market investors to create a capital pool;
- Provide energy efficiency loans to households that would be assured to result in greater utility bill savings than the loan repayment amount, sometimes requiring longer than traditional amortization periods;
- Tie loans to the meter, meaning that when the homeowner sells the house, the new owner can assume the loan;
- Insure the operation and performance of energy efficiency retrofits;
- Provide a guaranteed return to investors; and
- Offer collection of payments through the utility bill.

Market Research

The FortisBC Utilities and BC Hydro (“the Utilities”) conducted focus group sessions in Nov 2010 across the Lower Mainland, Prince George, and Kamloops to test consumer interest in energy efficiency financing and preferences for loan terms and conditions, as well as the best way to engage them. The FortisBC Utilities contributed approximately $12,000 towards conducting this research. Focus group testing found limited interest in an energy efficiency financing program operated by the Utilities. Most participants preferred to self-finance their energy efficiency upgrades and viewed the Utilities as competitors to banks for such an offering. Many participants noted that they already have a relationship with their banks and would be less inclined to take money from a utility and go through the hassle of transferring the payment to the next homeowner.

Program Issues

Although the PAYS model has some merit, the Companies have significant concerns that the PAYS model is overly complex and creates significant legal responsibility around the quality of the energy efficiency retrofits and guaranteeing that energy savings will exceed monthly payments after retrofits are completed. There are also significant concerns that loan payment defaults could be larger than energy bill payment defaults and in the absence of any loan default fund, the Companies would have to recover the defaults from the entire customer base. Additionally, the administrative burden associated with the collection of payments and the transfer of the loan to the next customer through property disclosure statements is complicated and outside the scope of the Utilities’ expertise.

Further discussions revealed that there remain a number of additional challenges and complexities to developing the financing aspect of this type of program, including:

1. A number of financial institutions (i.e. VanCity, Royal Bank of Canada, and Toronto Dominion Bank) already offer financial services specifically targeting energy efficiency

upgrades. A utility-operated program could be viewed as competing with the financial services industry;

2. The Utilities do not have the expertise to implement and operate large-scale loan programs;
3. A province-wide energy efficiency financing program would expose the Utilities to additional financial risk and potentially affect their overall ability/cost to borrow; and
4. The Companies are in the process of transitioning to a new customer billing service provider and will not have the ability to administer a financing program on their billing system for two to three years.

2011 Action Plan

To address some of the concerns identified above, the Companies and BC Hydro have put forward a proposal to explore energy efficiency financing further with the Ministry of Energy and Mines. This includes proposing an offer that focuses on partnering with financial institutions to introduce and expand energy efficiency financing programs. The Utilities would use their market presence to issue criteria (i.e. request of qualification) for financial institutions to become eligible providers of financing for a joint utilities renovation program. The intention would be to drive more favorable terms and conditions for participating customers with all the eligible financing providers. Financial institutions will benefit in a number of ways including enhanced marketing opportunities, lower cost customer generation, and leads into other program offers through their companies. The Companies believe some of the identified concerns about loan default and reputational risk can be partly mitigated through such a mechanism since the banks would provide the required loans and collect the payments through their existing channels, with no promise of savings exceeding monthly payments. In order to proceed with developing this proposed revised approach, the Companies are currently working with the Ministry of Energy and Mines to explore this option and assess the concerns of the Ministry before reaching out to the financial institutions. In the event this program moves forward as a pilot, the Companies would communicate with the Commission staff in the forthcoming stakeholder workshops.

11.4 Summary

Enabling Activities are important initiatives that support broader EEC activities and programs. The Companies initiated these activities in 2009 and continue to expand on them to support EEC activity with the inclusion of Energy Management Funding in 2010 to further create supportive conditions for a successful 2011 EEC portfolio.

Research and evaluation activities will continue to support the overall EEC portfolio and help provide direction to future program areas and enabling activity planning. The Efficiency Partners program will expand to include the FEI service area by potentially adding another 1,000 contractors to deliver EEC programs. Given the aggressive provincial GHG emissions targets, participation in the development of the new construction building code will strengthen the Companies' communication with the building industry. Hot water tank regulations and Tier 3 pilots will be necessary for the development of an effective market transformation plan to help protect the end use customer.

Many of these enabling activities are supportive of the province's Energy Plan. The degree of the Companies' work in Enabling Activities will be evaluated over the course of the year to determine whether the Efficiency Partners program and work on codes and standards require the establishment of a discrete budget.

12 EEC STAKEHOLDER GROUP ACTIVITIES

As one of the accountability measures defined in the EEC Decision, the Companies held two EEC stakeholder meetings in 2010. The objective of the EEC Stakeholder Group is to guide and provide input on EEC activities and programs. The purpose of the biannual workshops is for the Companies to present updates on program progress, act as a forum for dialogue for stakeholders input in developing new programs, and refining existing programs. The members of the EEC Stakeholder Group were solicited through regulatory stakeholders (those that have historically intervened in the Companies' regulatory proceedings) from industry groups with whom the Companies interact, and from key contacts from the Companies' Energy Solution and Community Relations departments. Refer to Appendix G in the meeting minutes for a list detailing membership of the EEC Stakeholder Group.

12.1 Activities and Costs in 2010

Two stakeholder meetings were held in 2010 - March 11 and November 24.

On March 11, 2010 the EEC department reviewed the 2009 EEC Annual Report with program investments and results. In addition, the stakeholders provided written feedback and action items for the Companies to pursue in 2010. On November 24, 2010 the EEC department reviewed programs and initiatives that had launched in 2010, correlating the successes back to many of the priorities from the March meeting, and then held mini-workshops with the stakeholders for program ideas to pursue in 2011. Both sessions have been well attended with positive verbal feedback on much of the EEC programs and initiatives, and active discussions that aid in prioritizing future EEC projects (i.e. programs for multifamily buildings and replacing mid-efficient furnaces that are still in residential homes).The meeting agendas, meeting minutes, lists of attendees, presentations, and stakeholder priorities and action items for the two 2010 meetings can be found in Appendix G.

Table 12-1 summarizes the costs for the stakeholder sessions.

Table 12-1: Cost for 2010 EEC Stakeholder Sessions (March and November)

Item	Actual Costs
Venues and equipment rental	$2,030
Meals	$4,332
Stakeholder travel	$4,456
Total Costs	$10,818

12.2 Planned Activities in 2011

In 2011, the Companies will continue to hold biannual workshops with the EEC Stakeholder Group with the first meeting having already taken place on March 15.

Additionally, the Companies intend to expand the EEC Stakeholder Group to include additional members, in particular representatives from the industrial, innovative technologies, and non-profit sectors, in order to reflect the expanding number of EEC programs available for the marketplace. As the EEC Stakeholder Group is expected to grow, the proposed budget in Table 12-2 below will reflect this growth. Stakeholder travel is expected to increase to encourage participation from representatives outside of the Lower Mainland. For example, industrial customers from northern BC, non-profit association representatives, and other government representatives

Table 12-2: Proposed Budget for 2011 EEC Stakeholder Sessions (Q1 and Q4)

Item	Budgeted Cost
Venues and Equipment Rental	$2,500
Meals	$4,600
Stakeholder travel and administration	$8,500
Budgeted Total	$15,600

The March 15 meeting to the expanded EEC Stakeholder group included presentations on the 2010 program results, highlights from the Conservation Potential Review study, which is still being finalized during the submission of this report, alternatives to the Total Resource Cost test used in program design, and discussion on the upcoming 2012 EEC funding application to the Commission.

The agenda, meeting minutes, presentations, and list of stakeholder prioirites for 2011 from the March 2011 EEC Stakeholder meeting can be found in Appendix G.

13 CONSERVATION POTENTIAL REVIEW ("CPR")

13.1 Introduction

Results of a Conservation Potential Review ("CPR") form the basis for future program development within a comprehensive EEC portfolio. The Companies drew heavily on the 2006 CPR as they moved from the small set of DSM activities to the broader portfolio of EEC initiatives. The Companies initiated a new CPR study in August 2010, hiring Marbek Resource Consultants Ltd. ("Marbek") to conduct the study at a cost of approximately $560,000. This study focused on the Companies' natural gas customers only and was segmented into the residential, commercial, and industrial sectors.

The Companies consider the CPR to be an important tool for use in developing, supporting, and assessing current and future EEC expenditure applications as well as for directional input into program development. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy efficiency and conservation programs over the study period. The CPR does this by comparing the economic and achievable potential of viable measures to a base case scenario.

13.2 Scope of Work

Overall, the 2010 CPR had the following key objectives/deliverables:

- Characterization of available natural gas and other thermal technologies inclusive of energy efficiency and fuel choice;
- Identification of the size of the potential opportunities over a set study period including opportunities related to equipment, lifestyle, and behaviour;
- Economic modeling of measures, including calculations on GJ output, GHG emissions, and cost/benefit analysis of all identified thermal technology options;
- Proportion of end use energy that could be met by energy systems based on renewable energy as the primary fuel with a natural gas and/or thermal component;
- Determination of how many jobs the Companies' natural gas conservation and efficiency activities would create in British Columbia up to 2021;
- Provision of estimates for the potential natural gas load reduction and GHG emissions reduction volume achievable through EEC programs for input into load forecasts and future integrated resource plans; and
- Provision of a discussion paper that looks beyond the traditional economic focused California Standard Practice tests and how utility energy efficiency and conservation

efforts could support government policy as listed in the 2010 BC Clean Energy Act (Bill 17).

In addition, Marbek was directed to conduct a commercial end use study as part of the 2010 CPR. This study analyzed the energy usage behaviour exhibited by small and large commercial customers by sector, including apartment/condo strata corporations, commercial/office, education, health care, restaurants, and wholesale/retail.

13.3 Results Delivery

The contract to conduct the CPR was awarded in August 2010 with work beginning in September 2010. Field work was conducted through October and November 2010. The draft Reference Case, Technology and Economic Potential chapters were produced in December 2010. Achievable potential workshops were held in January 2011. The final CPR report is expected to be completed at the end of March 2011.

When it is completed, the updated 2010 CPR will form the primary basis of the Companies' EEC funding requests for 2012 and beyond, and will be used as a reference document for program development.

Due to the finalization of the CPR study being so close to the submission date of this Report, it is not possible to include a discussion of the study's results here; however, the final CPR report will be submitted as an appendix to the Companies' upcoming Revenue Requirement Application.

14 DATA GATHERING REPORTING AND INTERNAL CONTROL PROCESSES

14.1 Introduction

In its EEC Decision, the Commission directed the Companies to include a discussion in the EEC Annual Report of the Companies' internal data gathering, monitoring, and reporting control practices. This section addresses that directive. As this section demonstrates, the Companies have business practices in place to ensure EEC activities and associated spending are in compliance with the Commission Orders and internal control processes of the Companies in general.

This section provides general information on data gathering and on the Companies' business practices related to program development and application processing. It also includes comments from the Companies' internal audit group on EEC initiative controls.

14.2 DSM System Project: Update

As was reported in the 2009 EEC Annual Report, the expansion of EEC programs resulting from the EEC Decision has created a need to develop a robust data capture and reporting system. With the increase in the number of programs and participants, the existing Excel-based DSM tracking and reporting methods are not capable of handling the future business needs and requirements of the EEC activities. As a result, the Companies determined that a new tracking system was needed to enable it to:

- Track EEC program participation, costs, and energy savings for incentive-based programs;
- Track information about non-incentive programs and activities;
- Track actual and forecasts vs. budgets;
- Provide reports for internal and external stakeholders including program partners and the Commission;
- Allow for scenario modeling for program planning and design; and
- Support DSM cost-benefit analysis on a program by program basis as well as at the portfolio level (or EEC plan level).

To address the requirement for more robust program data gathering, tracking, and reporting, the DSM System ("DSMS") project was launched in the fall of 2008. The Companies eventually selected a web-based program tracking and reporting system called TrakSmart, and entered into an Agreement with TrakSmart's provider Nexant, to obtain the TrakSmart system.

Project implementation commenced early in 2010 and through the process of implementing TrakSmart, it was identified that more internal resources would be required to integrate the system. Adapting the new system to a natural gas DSM environment also proved to be more challenging than expected. Several software patches, system enhancements, and training sessions were required to configure the system to suit the Companies' needs. As a result, the launch of DSM programs into TrakSmart for production use was delayed. It is now expected the DSMS will be operational for an initial set of programs by April 2011. Assuming the system works as designed and expected, the full set of DSM programs from 2009 to present will be integrated into the TrakSmart system for reporting purposes and program administration.

The costs associated with implementing and maintaining the DSMS have been added to the portfolio level expenditures in 2010. The costs to implement DSMS in 2010 were approximately $645,000. It is estimated that an additional $380,000 will be required to complete the software implementation in 2011.

Once the DSMS is implemented, it will increase the ability of the Companies to capture and report on the following features:

- Program participants' information, costs, and energy savings for EEC programs and activities;
- Forecasting / extrapolation based on estimates and actuals;
- Expenses and budget tracking associated with EEC projects;
- Interface with SAP20 application;
- Costs (program, incentive, and administration) associated with EEC projects; and
- Capture of information on a per participant basis (i.e. equipment models, reasons for rejection and so on).

Once the DSMS is in place and the transition period from the current system to the new system is completed, these features will help the EEC team to make data gathering, tracking, and reporting more efficient and increase the overall efficiency of the workflow.

14.3 Robust Business Case Process Applied to All Programs

Before a new EEC program can be implemented, a program plan or business case must first be developed. The Companies are committed to putting each program through a high level of internal scrutiny before moving ahead with a program, and believe doing so ensures an increased chance of program effectiveness.

The business case developed includes information about program rationale and purpose, as well as a description of the target audience, assumptions, cost-benefit tests, and proposed evaluation methods.

Cost-benefit analysis is performed using the California Standard Tests ("CST") as outlined in the California Standard Practice Manual. In partnership with Willis Energy Services Ltd., the Companies have developed an in-house cost-benefit modeling tool based on CST that provides the following areas of analysis:

- Benefits incurred over measure life of the individual programs, including energy savings over the measure life of the program;
- Total costs incurred in implementing the program, including administrative, incentive, marketing, and evaluation; and
- The four CST tests (Rate Impact Measure ["RIM"], Utility, Participant, and TRC).

The results from this modeling are used as inputs for the business cases, which are approved in accordance with the Companies' policy on financial authorization levels.

14.4 Incentive Applications Vetted for Compliance with Program Requirements

Ensuring all customer applications are compliant with program eligibility requirements as laid out in program terms and conditions is also part of the internal control process. The Companies have a number of mechanisms in place to ensure EEC incentive funding applications are in compliance with program requirements.

The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive, and other parameters. The general principles applied are as follows:

1. Each application is reviewed for completeness and accuracy;
2. Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process. Please refer to Appendix I for a copy of Efficient Boiler program's terms and conditions as an example;
3. Once approved, incentives are distributed to participants; and
4. Copies of application and supporting documents are filed and stored for seven years in case of an audit.

14.5 Internal Audit Services

The EEC team engaged the Companies' own Internal Audit Services ("IAS") group to review the internal controls associated with the EEC initiative. Generally speaking, IAS found the internal controls established for the EEC initiative were functioning as intended.

The report from the Companies' IAS group can be found in Appendix J.

14.6 Summary

The Companies are committed to strong internal controls in all aspects of the EEC program. As demonstrated in this section, the Companies' business practices related to program development, application processing, and ongoing monitoring are all sound and subject to continuous improvement.

The Companies' EEC team is implementing a robust data gathering and program participation tracking system (the DSMS) in order to accommodate the increased level of EEC activity arising from the funding approval. Expenditures reported through the DSMS will be gathered from SAP, which tracks all of the Companies' financial activity. It is expected this system will be in full production use by mid-2011.

All business case and financial approvals are performed in accordance with the Administrative Policy on the Companies' Authorization Levels. There are solid business practices in place related to EEC activity, such as a requirement for a detailed business case for all new programs and initiatives.

The Companies' IAS group has reviewed the processes of the EEC team and generally speaking, internal controls are functioning as intended.

In 2011 and beyond, the Companies will continue to monitor their internal controls and work with IAS to implement the changes contained in their report, so that all aspects of the EEC program are carried out with appropriate diligence and scrutiny.

15 THE COMPANYS' EEC PRINCIPLES

In the original EEC Application, the Companies laid out a number of EEC principles that are intended to guide our EEC activity. This section revisits those principles and discusses how the Companies' EEC activity completed in 2010 and planned activity for 2011 meets these principles.

1. *Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers through the DSM for Affordable Housing initiative.*
    - As can be seen by the significant variety of programs described in this report, the Companies have implemented EEC initiatives aimed at all customers including residential, commercial, industrial, and low income.

2. *Wherever possible, programs will be uniform, so that customers in one part of the service territories of the FortisBC Energy Utilities have access to the same programs as customers throughout the service territories.*
    - Programs described in this report are available to customers in all the Companies' service territories, with the following exceptions:
        - The Companies do not currently have funding approval for EEC activity for interruptible industrial customers on Vancouver Island; and
        - The Companies do not currently have funding approval for EEC activity for customers in Whistler.
    - The vast majority of customers, however, have access to all the programs for which their rate class is eligible, and it is the intent of the Companies to include funding for interruptible industrial customers on Vancouver Island and for customers in Whistler in the next EEC funding request in the 2012 – 2013 Revenue Requirements Application.

3. *EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year.*
    - The Companies' expenditures in 2010 are aligned with this principle: incentive expenditures were approximately $11.5 million and non-incentive expenditures were approximately $6.2 million.

4. *Program results will be analyzed on a portfolio-wide basis.*

5. *The Total Resource Cost/Benefit of the Portfolio over the funding period will have a ratio of 1 or higher.*

    - As can be seen in Table 2-1 in Section 2, the portfolio-level TRC results for the Companies' EEC activities in 2010 was 1.1, thus Principles four and five have both been met.

6. *The FortisBC Energy Utilities will submit an Annual EEC Report to the BCUC, by the end of the first quarter of each year, that details the results of the previous year's programs and anticipates program activity and spending for the upcoming (current) year.*

    - This report is that document.

7. *To every extent practical, programs will support the objectives of established government policies.*

    - In the Clean Energy Act (attached as Appendix C), government laid out a number of energy objectives. The Companies' EEC activity supports a number of these objectives including the following:
        - *To take demand-side measures and to conserve energy:*
            - The Companies' EEC initiative in its entirety supports this objective.
        - *To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources:*
            - This objective is supported primarily through the Innovative Technologies program area.
        - *To reduce BC greenhouse gas emissions:*
            - Again, the Companies' overall EEC initiative supports this objective.
        - *To encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emission in British Columbia:*
            - This is not only supported by high-carbon fuel switching, but also by the Innovative Technologies program area.
        - *To encourage communities to reduce greenhouse gas emissions and use energy efficiently:*
            - This is supported primarily by Conservation Education and Outreach programs.
        - *To encourage economic development and the creation and retention of jobs:*
            - This is another objective that is supported by the Companies' EEC initiative overall.

8. *The Companies will continue to seek funding for programs from additional sources, such as the provincial and federal governments, other utilities, and equipment suppliers and manufacturers, in order to minimize the cost impacts of EEC programs to ratepayers, and in recognition of the broader societal benefits resulting from successful program development and implementation.*

    - The Companies have been successful in meeting this program principle, primarily through the MEMPR low income grant discussed in Section 6.

9. *Incentives may be directed to the end users of an appliance, to the customer point of contact at the time that an equipment purchase decision is made (for example, to the gas contractor in the case of a furnace), to a system designer or engineer, or to an equipment developer, supplier or manufacturer. The most effective use of incentives will be determined through the program design process.*

    - Although the majority of incentives offered in 2010 were aimed at the end users of appliances, the Companies determined that in the case of the EnerChoice Fireplace program discussed in Section 3, a partial incentive should be paid to the salesperson. In the future, the Companies will explore opportunities to offer incentives to entities other than the end user, should it make sense to do so.

10. *Education and outreach regarding conservation will be part of the Companies' EEC activity.*

    - As discussed in Section 8, the Companies view Conservation Education and Outreach programs to be a crucial component of a successful EEC initiative, and we look forward to expanding these efforts in the coming years.

11. *Programs will be multi-year so as to create a sense of funding certainty necessary to effective implementation in the marketplace – this Application requests funding for a three-year Portfolio of EEC programs.*

    - Most of the programs offered in 2010 were multi-year programs. The Companies recognize that currently-approved EEC funding expires at the end of 2011, and are planning to request an expanded funding envelope for 2012 and 2013 in the Revenue Requirements Application to be filed in May 2011.

12. *Programs will have market transformation as their ultimate goal, and program plans will describe how a program will contribute to market transformation.*

    - One key example of this principle in action is the 0.80 EF Water Heater pilot, described in Section 3, where government has announced its intention to implement a minimum efficiency standard of 0.80 for residential gas water heaters. Led by the Companies, gas utilities across the country will be exploring the installation and performance of 0.80 EF technologies in preparation for the introduction of regulation requiring 0.80 EF as the minimum efficiency.

13. *Programs will aim to develop capacity within the market through manufacturers, distributors, vendors and installers.*

    - Some examples of capacity-building programs include the Energy Specialist program discussed in Section 11, the REnEW program discussed in Section 6, and the Furnace Service Campaign discussed in Section 3.

14. *To ensure value creation and alignment with the market, the Companies will establish and engage an EEC stakeholder group, comprised of governments, industry, trades, manufacturers, NGOs, advocacy groups, other utilities and customers to provide it with advice on effective program design and implementation, as well as some oversight of the Companies' EEC activity and expenditure. Consideration may be given by the Companies to consolidate the Companies' EEC Stakeholder activity with stakeholder activity currently being undertaken by other utilities in order to reduce potential "stakeholder fatigue".*

    - *The Companies are pleased with the interest and input from the stakeholder group established for the EEC* initiative. Stakeholder activity is discussed in Section 12.

In conclusion, the Companies feel the EEC activity in 2010 has complied with the EEC principles laid out in the original EEC Application.

Appendix A

GLOSSARY OF TERMS

GLOSSARY OF TERMS

ABSU – Accenture Utilities Business Process Outsourcing Services

AFUE – Annual Fuel Utilization Efficiency

AHRI – Air-Conditioning, Heating, and Refrigeration Institute

BCAOMA – British Columbia Apartment Owners & Managers Association

BCHL – BC Hockey League

BC Hydro – British Columbia Hydro and Power Authority

BCSEA – British Columbia Sustainable Energy Association

BCUC – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

BTU - British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit

CCE – Consortium for Energy Efficiency

CEA – Clean Energy Act (Bill 17 – 2010)

CEC – Commercial Energy Consumers Association of British Columbia

CEO – Conservation Education and Outreach

CHBA – Canadian Home Builders' Association

CHF – Co-operative Housing Federation

CIPH – Canadian Institute of Plumbing and Heating

CNG – Compressed Natural Gas

Commission – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia.

Companies – FortisBC Energy Utilities

COV – City of Vancouver

CPR – Conservation Potential Review, a study completed to identify opportunities for energy savings across natural gas delivery infrastructures and improvements to overall energy utilization efficiency.

CS – Compression Service

CST – California Standard Tests

CWHI - Condensing Water Heater Initiative

DC – Pacific Resource Conservation Society's Destination Conservation program

DES - District Energy Systems

DHW – Domestic Hot Water

DSM – Demand-Side Management, defined as "any utility activity that modifies or influences the way in which customers utilize energy services". From FortisBC Energy Utilities' perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

DSMS – Demand Side Management System

ECAP - Energy Conservation Assistance Program

ECM - Electronically Commutated Motors

EEC – Energy Efficiency and Conservation

EEC Application – 2008 Energy Efficiency and Conservation Programs Application

EEC Decision – BCUC Order No. G-36-09

EF – Efficiency Factor

ESK - Energy Saving Kit

FE – Fireplace Efficiency

FEI - FortisBC Energy Inc.

FEU - FortisBC Energy Utilities

FEVI - FortisBC Energy (Vancouver Island) Inc.

FortisBC Energy Utilities - FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc.

Fraser Basin – Fraser Basin Council

Free Rider Rate – percent who would have implemented an energy efficiency measure even without the program.

GHGs – Greenhouse Gas Emissions

GJ – Gigajoule – a measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GSHP – Ground Source Heat Pump

HPBAC – Hearth, Patio & Barbecue Association of Canada

HEX Pilot – Heat Exchanger Pilot Program

IAS – Internal Audit Services

Interim Decision – BCUC Order No. G-6-11

IRs – Information Requests

IT – Information Technology

K – 12 – Kindergarten to Grade 12

LEAP – LiveSmart BC Energy Assistance Program

LiveSmart BC – LiveSmart BC Efficiency Incentive Program

LNG – Liquefied Natural Gas

LTRP – 2010 Long Term Resource Plan

MBH - 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

MEM – Ministry of Energy and Mines

MOU – Memorandum of Understanding

MURB – Multi-Unit Residential Buildings

MVHC – Metro Vancouver Housing Corporation

NGV – Natural Gas Vehicle

NPV – Net Present Value

NRCan – Natural Resources Canada

NSA – Negotiated Settlement Agreement

NSP – Negotiated Settlement Process

OEM – Original Equipment Manufacturer

O&M – Operating and Maintenance Costs

Participant Test – is the measure of the quantifiable benefits and costs to the customer due to participation in a program.

PCT – Pacific Carbon Trust

PBR – Performance Based Rate

PBR Settlement Agreement – Multi-Year Performance Based Rate Plan Settlement Agreement

QDP – Qualified Dealers Program

REnEW - Residential Energy and Efficiency Works

Report – EEC Annual Report

REUS – Residential End Use Survey

RIM – Rate Impact Measure test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

RRA – Revenue Requirements Application

SAP - System, Applications and Products - financial tool in which EEC expenditures are captured within

SEMP - Strategic Energy Management Plan

SENC - Super Efficient New Construction

SHIFT - Sustainability and Social Responsibility Attitudes Study

SPIFF – Sales Promotion Incentive Fund

Task Force – Affordable Energy Conservation Task Force

TBD – To be determined after filing of the EEC Annual Report

TJ – Terajoule – equal to 1000 gigajoules.

TRC – Total Resource Cost test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

Utility Cost Test – measures the net costs of demand-side management programs as a resource option based on the costs incurred by the utility (including incentive costs) and exclude the net costs incurred by the participant.

WM – Waste Management of Canada Corporation

WHIMIS - Workplace Hazardous Materials Information System

Appendix B
COST BENEFIT ANALYSIS

2010 DSM Actuals

	PROGRAM									ALTERNATE		NET PRESENT VALUE									Benefits/cost test						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings					Participant				
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon	Alternate	Natural Gas	Alternate	Alternate	Natural	Total	Total		Natural		TRC Net
	Incentives	Administr	Total	Participant	Total	% Utility	%	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate	Total	($'000s)
2010 Actuals																											
Residential Energy Efficiency Programs																											
2010 Residential Total	2,803	440	3,242	3,302	6,544	50%	50%	108,346	62,036	2	-	5	6,141	2	6,798	890	1	606,851	13	-	1.9	3,302	7,689	2.3	0.6	0.9	(402)
Commercial Energy Efficiency Programs																											
2010 Commercial Total	2,401	170	2,570	3,655	6,225	41%	59%	126,585	103,856	2,049	-	3	8,313	2,376	9,634	1,211	1,538	815,113	19,803	-	3.2	3,655	12,383	3.4	0.7	1.7	4,464
Joint Initiatives																											
2010 Joint Initiatives Total	29	429	458	0	487	94%	0%	864	748	0	-	80	56	0	61	8	0	5,700	-	-	0.1	-	70	N/A	0.1	0.1	(431)
Conservation for Affordable Housing Programs																											
2010 Affordable Housing Total	49	275	324	0	324	100%	0%	4,517	3,297	0	-	17	244	0	222	30	0	19,479	-	-	0.8	-	252	N/A	0.4	0.8	(80)
Innovative Technology																											
2010 Innovative Technology Total	5,959	5	5,964	1,449	7,840	76%	18%	(161,228)	(161,228)	4,180	-	FS	(6,728)	17,707	(7,203)	(1,099)	17,707	(706,551)	19,675	-	FS	9,751	17,707	1.8	0.6	1.2	3,140
High carbon fuel switching																											
2010 High Carbon Fuel Switching Total	178	123	301	0	301	100%	0%	(7,654)	(3,827)	8	-	FS	(398)	976	(564)	(57)	976	(38,632)	44	-	FS	621	976	1.6	0.8	1.4	277
Portfolio Level Expenditure												-															
2010 Portfolio Level Total		**4,842**										-															
2010 TOTAL	**11,419**	**6,283**	**17,702**	**8,406**	**26,562**	**67%**	**32%**	**71,429**	**4,882**	**6,239**	**0**	25	**7,628**	**21,061**	**8,949**	**983**	**20,222**	**701,959**	**39,535**	**0**	**0.4**	**8,406**	**30,154**	**3.6**	**0.3**	**1.1**	**2,127**

FORTIS BC

2010 FEI Programs Actuals	PROGRAM									ALTERNATE		NET PRESENT VALUE									Benefit/cost test						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings			Participant						
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2010																											
Residential Energy Efficiency Programs																											
Energy Efficiency Program	2,686	254	2,940	3,199	6,139	48%	52%	104,795	59,965	0	-	5	5,929	0	6,480	859	0	586,021	-		2.0	3,199	7,339	2.3	0.6	1.0	(210)
Non Program Specific Admin Cost		74																	-	-							
2010 Residential Total	**2,686**	**328**	**3,014**	**3,199**	**6,213**	**48%**	**52%**	**104,795**	**59,965**	**0**	**-**	**3**	**5,929**	**0**	**6,480**	**859**	**0**	**586,021**	**0**	**0**	**2.0**	**3,199**	**7,339**	**2.3**	**0.6**	**1.0**	**(284)**
Commercial Energy Efficiency Programs																											
Energy Efficiency Program	1,964	81	2,045	3,032	5,078	40%	60%	102,164	82,678	1,768	-	3	6,739	2,061	6,820	976	1,321	658,188	17,177	-	3.3	3,032	9,117	3.0	0.8	1.7	3,723
Non Program Specific Admin Cost		39																									
2010 Commercial Total	**1,964**	**120**	**2,084**	**3,032**	**5,116**	**44%**	**59%**	**102,164**	**82,678**	**1,768**	**-**	**3**	**6,739**	**2,061**	**6,820**	**976**	**1,321**	**658,188**	**17,177**	**-**	**3.2**	**3,032**	**9,117**	**3.0**	**0.8**	**1.7**	**3,684**
Joint Initiatives																											
Energy Efficiency Program	14	371	385	0	414	93%	7%	864	748	0	0	67	56	0	61	8	0	5,700	0	0	0.1	29	70	2.4	0	0.1	(358)
Non Program Specific Admin Cost		48																									
2010 Joint Initiatives Total	**14**	**419**	**433**	**0**	**462**	**93%**	**7%**	**864**	**748**	**0**	**-**	**67**	**56**	**0**	**61**	**8**	**0**	**5,700**	**0**	**0**	**0.1**	**-**	**70**	**N/A**	**0.1**	**0.1**	**(406)**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	39	213	253	0	253	100%	0%	3,613	2,637	0	0	16	194	0	164	24	0	15,520	0	0	0.8	0.0	187	0.0	0.5	0.8	(59)
Non Program Specific Admin Cost		43																									
2010 Affordable Housing Total	**39**	**256**	**296**	**0**	**296**	**100%**	**0%**	**3,613**	**2,637**	**0**	**0**	**16**	**194**	**0**	**164**	**24**	**0**	**15,520**	**0**	**0**	**0.7**	**-**	**187**	**N/A**	**0.4**	**0.7**	**(102)**
Innovative Technology																											
Energy Efficiency Program	5,816	2	5,818	958	7,040	83%	14%	(162,911)	(162,911)	4,180	0	FS	(6,937)	17,707	(7,567)	(1,128)	17,707	(726,396)	19,675	0	FS	9,653	17,707	1.8	0.6	1.3	3,730
Non Program Specific Admin Cost		3																									
2010 Innovative Technology Total	**5,816**	**5**	**5,821**	**958**	**7,043**	**83%**	**14%**	**(162,911)**	**(162,911)**	**4,180**	**0**	**FS**	**(6,937)**	**17,707**	**(7,567)**	**(1,128)**	**17,707**	**(726,396)**	**19,675**	**0**	**FS**	**9,653**	**17,707**	**1.8**	**0.6**	**1.3**	**3,727**
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	29	46	75	0	75	100%	0%	(1,247)	(624)	1	0	FS	(61)	159	(67)	(9)	159	(6,103)	7	0	FS	76.4	159	2.1	0.5	1.2	23
Non Program Specific Admin Cost		1																									
2010 High Carbon Fuel Switching Total	**29**	**47**	**76**	**0**	**76**	**100%**	**0%**	**(1,247)**	**(624)**	**1**	**0**	**FS**	**(61)**	**159**	**(67)**	**(9)**	**159**	**(6,103)**	**7**	**0**	**FS**	**76.4**	**159**	**2.1**	**0.5**	**1.2**	**23**
Portfolio Level Expenditure																											
Conservation Education & Outreach		1,415																									
Enabling Activities		70																									
Non Program Specific Portfolio Level Cost		1,289																									
Industrial Program Costs		4																									
Labor Costs		1,307																									
2010 FEI Portfolio Level Total		**4,085**																									
2010 Total	**10,548**	**5,261**	**15,809**	**7,189**	**23,292**	**68%**	**31%**	**47,278**	**(17,507)**	**5,949**	**0**	**29.7**	**5,920**	**19,928**	**5,891**	**730**	**19,187**	**532,929**	**36,859**	**0**	**0.4**	**7,189**	**25,808**	**3.6**	**0.3**	**1.1**	**2,556**

FORTIS BC VANCOUVER ISLAND

2010 FEVI Programs Actuals	PROGRAM									ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2010																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	117	76	193	103	296	65%	35%	3,551	2,072	2	-	9	212	2	318	31	1	20,830	13	-	1.1	103	350	3.4	0.4	0.7	(83)
Non Program Specific Admin Cost		35																									
2010 Residential Total	**117**	**111**	**228**	**103**	**331**	**65%**	**35%**	**3,551**	**2,072**	**2**	**0**	**9**	**212**	**2**	**318**	**31**	**1**	**20,830**	**13**	**0**	**0.9**	**103**	**350**	**3.4**	**0.4**	**0.6**	**(118)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	437	20	456	623	1,079	42%	58%	24,421	21,178	282	-	3	1,574	315	2,814	235	217	156,925	2,626	-	3.4	623	3,266	5.2	0.5	1.8	810
Non Program Specific Admin Cost		30																									
2010 Commercial Total	**437**	**49**	**486**	**623**	**1,109**	**44%**	**56%**	**24,421**	**21,178**	**282**	-	3	1,574	315	2,814	235	217	156,925	2,626	-	**3.2**	**623**	**3,266**	**5.2**	**0.5**	**1.7**	**780**
Joint Initiatives																											
Energy Efficiency Program	15	1	16	0	16	100%	0%	0	**0**	-	-	LB	-	-	-	-	-	-	-	-	**LB**	-	-	**N/A**	**N/A**	**LB**	**LB**
Non Program Specific Admin Cost		9																									
2010 Joint Initiatives Total	**15**	**10**	**25**	**0**	**25**	**100%**	0%	**0**	**0**	-	-	**LB**	-	-	-	-	-	-	-	-	**LB**	-	-	**N/A**	**N/A**	**LB**	**LB**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	**10**	**16**	**26**	**0**	**26**	**100%**	0%	**904**	**660**	-	-	**7**	**50**	-	**59**	**6**	-	**3,959**	-	-	**1.9**	-	**65**	**N/A**	**0.6**	**1.9**	**23**
Non Program Specific Admin Cost		2																									
2010 Affordable Housing Total	**10**	**19**	**28**	**0**	**28**	**100%**	**0%**	**904**	**660**	-	-	**7**	**50**	-	**59**	**6**	-	**3,959**	-	-	**1.8**	-	**65**	**N/A**	**0.6**	**1.8**	**22**
Innovative Technology																											
Energy Efficiency Program	143	0	143	491	796	18%	62%	1,683	1,683	0	-	7	209	0	364	29	0	19,845	-	-	1.5	1	393	0.8	0.4	0.3	**(587)**
Non Program Specific Admin Cost		0																									
2010 Innovative Technology Total	**143**	**0**	**143**	**491**	**796**	**18%**	**62%**	**1,683**	**1,683**	**0**	-	**7**	**209**	**0**	**364**	**29**	**0**	**19,845**	-	-	**1.5**	**491**	**393**	**0.8**	**0.4**	**0.3**	**(587)**
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	149	76	225	-	225	100%	0%	(6,407)	(3,204)	7	-	FS	(337)	817	(497)	(48)	817	(32,529)	37	-	FS	545	817	1.5	0.9	1.5	255
Non Program Specific Admin Cost		0																									
2010 High Carbon Fuel Switching Total	**149**	**76**	**225**	**0**	**225**	**100%**	**0**	(6,407)	(3,204)	**7**	**0**	**FS**	**-337**	**817**	**-497**	**-48**	**817**	(32,529)	**37**	**0**	**FS**	**545**	**817**	**1.5**	**0.9**	**1.5**	**255**
Portfolio Level Expenditure																											
Conservation Education & Outreach		201																									
Enabling Activities		41																									
Non Program Specific Portfolio Level Cost		232																									
Industrial Program Costs		0																									
Labor Costs		282																									
FEVI Portfolio level total		**756**																									
2010 Total	**870**	**1,022**	**1,892**	**1,217**	**3,271**	**58%**	**37%**	**24,151**	**22,389**	**290**	**0**	**11**	**1,708**	**1,133**	**3,058**	**253**	**1,035**	**169,030**	**2,676**	**0**	**0.9**	**1,217**	**4,346**	**3.6**	**0.3**	**0.9**	**(429)**

2010 DSM Actuals

	PROGRAM									ALTERNATE		NET PRESENT VALUE									Benefits/cost test						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings					Participant				
	Utility																										
	Incentives	Administr	Total	Participant	Total	% Utility	%	Gross	Net	Energy MWh	Capacity kW	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate (MWh)	Alternate (kW)	Natural Utility	Total ($'000s)	Total ($'000s)		Natural Rate	Total	TRC Net ($'000s)
2010 Actuals																											
Residential Energy Efficiency Programs																											
2010 Residential Total	2,803	440	3,242	3,302	6,544	50%	50%	108,346	62,036	2	-	5	6,141	2	6,798	890	1	606,851	13	-	1.9	3,302	7,689	2.3	0.6	0.9	(402)
Commercial Energy Efficiency Programs																											
2010 Commercial Total	2,401	170	2,570	3,655	6,225	41%	59%	126,585	103,856	2,049	-	3	8,313	2,376	9,634	1,211	1,538	815,113	19,803	-	3.2	3,655	12,383	3.4	0.7	1.7	4,464
Joint Initiatives																											
2010 Joint Initiatives Total	29	429	458	0	487	94%	0%	864	748	0	-	80	56	0	61	8	0	5,700	-	-	0.1	-	70	N/A	0.1	0.1	(431)
Conservation for Affordable Housing Programs																											
2010 Affordable Housing Total	49	275	324	0	324	100%	0%	4,517	3,297	0	-	17	244	0	222	30	0	19,479	-	-	0.8	-	252	N/A	0.4	0.8	(80)
Innovative Technology																											
2010 Innovative Technology Total	0	0	0	0	0 -	-		0	0	0	-	-	0	0	0	0	0	-	-	-	N/A	-	-	N/A	N/A	N/A	N/A
High carbon fuel switching																											
2010 High Carbon Fuel Switching Total	178	123	301	0	301	100%	0%	(7,654)	(3,827)	8	-	FS	(398)	976	(564)	(57)	976	(38,632)	44	-	FS	621	976	1.6	0.8	1.4	277
Portfolio Level Expenditure												-															
2010 Portfolio Level Total		**4,842**										-															
2010 TOTAL	**5,460**	**6,278**	**11,738**	**6,957**	**18,723**	**63%**	**37%**	**232,657**	**166,110**	**2,059**	**0**	8	**14,356**	**3,354**	**16,152**	**2,082**	**2,515**	**1,408,510**	**19,860**	**0**	**1.2**	**6,957**	**20,749**	**3.0**	**0.5**	**0.9**	**(1,013)**

FORTIS BC

2010 FEI Programs Actuals

2010 FEI Programs Actuals	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) – Gross	SAVINGS (GJ) – Net	ALTERNATE – Impact – Energy MWh	Impact – Capacity kW
2010											
Residential Energy Efficiency Programs											
Energy Efficiency Program	2,686	254	2,940	3,199	6,139	48%	52%	104,795	59,965	0	-
Non Program Specific Admin Cost		74									
2010 Residential Total	2,686	328	3,014	3,199	6,213	48%	52%	104,795	59,965	0	-
Commercial Energy Efficiency Programs											
Energy Efficiency Program	1,964	81	2,045	3,032	5,078	40%	60%	102,164	82,678	1,768	-
Non Program Specific Admin Cost		39									
2010 Commercial Total	1,964	120	2,084	3,032	5,116	44%	59%	102,164	82,678	1,768	-
Joint Initiatives											
Energy Efficiency Program	14	371	385	0	414	93%	7%	864	748	0	0
Non Program Specific Admin Cost		48									
2010 Joint Initiatives Total	14	419	433	0	462	93%	7%	864	748	0	-
Conservation for Affordable Housing Programs											
Energy Efficiency Program	39	213	253	0	253	100%	0%	3,613	2,637	0	0
Non Program Specific Admin Cost		43									
2010 Affordable Housing Total	39	256	296	0	296	100%	0%	3,613	2,637	0	0
Innovative Technology											
Energy Efficiency Program											
Non Program Specific Admin Cost											
2010 Innovative Technology Total											
High Carbon Fuel Switching											
High Carbon Fuel Switching Program	29	46	75	0	75	100%	0%	(1,247)	(624)	1	0
Non Program Specific Admin Cost		1									
2010 High Carbon Fuel Switching Total	29	47	76	0	76	100%	0%	(1,247)	(624)	1	0
Portfolio Level Expenditure											
Conservation Education & Outreach		1,415									
Enabling Activities		70									
Non Program Specific Portfolio Level Cost		1,289									
Industrial Program Costs		4									
Labor Costs		1,307									
2010 FEI Portfolio Level Total		4,085									
2010 Total	4,732	5,256	9,988	6,232	16,249	61%	38%	210,189	145,404	1,769	0

2010 FEI Programs Actuals	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	Benefit/cost test – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2010																
Residential Energy Efficiency Programs																
Energy Efficiency Program	5	5,929	0	6,480	859	0	586,021	-		2.0	3,199	7,339	2.3	0.6	1.0	(210)
Non Program Specific Admin Cost								-	-							
2010 Residential Total	3	5,929	0	6,480	859	0	586,021	0	0	2.0	3,199	7,339	2.3	0.6	1.0	(284)
Commercial Energy Efficiency Programs																
Energy Efficiency Program	3	6,739	2,061	6,820	976	1,321	658,188	17,177	-	3.3	3,032	9,117	3.0	0.8	1.7	3,723
Non Program Specific Admin Cost																
2010 Commercial Total	3	6,739	2,061	6,820	976	1,321	658,188	17,177	-	3.2	3,032	9,117	3.0	0.8	1.7	3,684
Joint Initiatives																
Energy Efficiency Program	67	56	0	61	8	0	5,700	0	0	0.1	29	70	2.4	0	0.1	(358)
Non Program Specific Admin Cost																
2010 Joint Initiatives Total	67	56	0	61	8	0	5,700	0	0	0.1	-	70	N/A	0.1	0.1	(406)
Conservation for Affordable Housing Programs																
Energy Efficiency Program	16	194	0	164	24	0	15,520	0	0	0.8	0.0	187	0.0	0.5	0.8	(59)
Non Program Specific Admin Cost																
2010 Affordable Housing Total	16	194	0	164	24	0	15,520	0	0	0.7	-	187	N/A	0.4	0.7	(102)
Innovative Technology																
Energy Efficiency Program																
Non Program Specific Admin Cost																
2010 Innovative Technology Total																
High Carbon Fuel Switching																
High Carbon Fuel Switching Program	FS	(61)	159	(67)	(9)	159	(6,103)	7	0	FS	76.4	159	2.1	0.5	1.2	23
Non Program Specific Admin Cost																
2010 High Carbon Fuel Switching Total	FS	(61)	159	(67)	(9)	159	(6,103)	7	0	FS	76.4	159	2.1	0.5	1.2	23
Portfolio Level Expenditure																
Conservation Education & Outreach																
Enabling Activities																
Non Program Specific Portfolio Level Cost																
Industrial Program Costs																
Labor Costs																
2010 FEI Portfolio Level Total																
2010 Total	7.9	12,857	2,220	13,458	1,859	1,480	1,259,325	17,184	0	1.3	6,232	16,796	2.7	0.5	0.9	(1,171)

FORTIS BC VANCOUVER ISLAND

2010 FEVI Programs Actuals	PROGRAM COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) Gross	SAVINGS (GJ) Net	ALTERNATE Impact Energy MWh	ALTERNATE Impact Capacity kW	NET PRESENT VALUE Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Participant Benefits (Costs) Carbon Tax ($'000s)	Participant Benefits (Costs) Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Program Net Savings Alternate Energy (MWh)	Program Net Savings Alternate Capacity (kW)	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2010																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	117	76	193	103	296	65%	35%	3,551	2,072	2	-	9	212	2	318	31	1	20,830	13	-	1.1	103	350	3.4	0.4	0.7	(83)
Non Program Specific Admin Cost		35																									
2010 Residential Total	**117**	**111**	**228**	**103**	**331**	**65%**	**35%**	**3,551**	**2,072**	**2**	**0**	**9**	**212**	**2**	**318**	**31**	**1**	**20,830**	**13**	**0**	**0.9**	**103**	**350**	**3.4**	**0.4**	**0.6**	**(118)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	437	20	456	623	1,079	42%	58%	24,421	21,178	282	-	3	1,574	315	2,814	235	217	156,925	2,626	-	3.4	623	3,266	5.2	0.5	1.8	810
Non Program Specific Admin Cost		30																									
2010 Commercial Total	**437**	**49**	**486**	**623**	**1,109**	**44%**	**56%**	**24,421**	**21,178**	**282**	-	3	1,574	315	2,814	235	217	156,925	2,626	-	**3.2**	**623**	**3,266**	**5.2**	**0.5**	**1.7**	**780**
Joint Initiatives																											
Energy Efficiency Program	15	1	16	0	16	100%	0%	0	**0**	-	-	LB	-	-	-	-	-	-	-	-	**LB**	-	-	**N/A**	**N/A**	**LB**	**LB**
Non Program Specific Admin Cost		9																									
2010 Joint Initiatives Total	**15**	**10**	**25**	**0**	**25**	**100%**	0%	**0**	**0**	-	-	**LB**	-	-	-	-	-	-	-	-	**LB**	-	-	**N/A**	**N/A**	**LB**	**LB**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	**10**	**16**	**26**	**0**	**26**	**100%**	0%	**904**	**660**	-	-	**7**	**50**	-	**59**	**6**	-	**3,959**	-	-	**1.9**	-	**65**	**N/A**	**0.6**	**1.9**	**23**
Non Program Specific Admin Cost		2																									
2010 Affordable Housing Total	**10**	**19**	**28**	**0**	**28**	**100%**	**0%**	**904**	**660**	-	-	**7**	**50**	-	**59**	**6**	-	**3,959**	-	-	**1.8**	-	**65**	**N/A**	**0.6**	**1.8**	**22**
Innovative Technology																											
Energy Efficiency Program																											
Non Program Specific Admin Cost																											
2010 Innovative Technology Total																											
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	149	76	225	-	225	100%	0%	(6,407)	(3,204)	7	-	FS	(337)	817	(497)	(48)	817	(32,529)	37	-	FS	545	817	1.5	0.9	1.5	255
Non Program Specific Admin Cost		0																									
2010 High Carbon Fuel Switching Total	**149**	**76**	**225**	**0**	**225**	**100%**	**0**	(6,407)	(3,204)	**7**	**0**	**FS**	**-337**	**817**	**-497**	**-48**	**817**	(32,529)	**37**	**0**	**FS**	**545**	**817**	**1.5**	**0.9**	**1.5**	**255**
Portfolio Level Expenditure																											
Conservation Education & Outreach		201																									
Enabling Activities		41																									
Non Program Specific Portfolio Level Cost		232																									
Industrial Program Costs		0																									
Labor Costs		282																									
FEVI Portfolio level total		**756**																									
2010 Total	**727**	**1,022**	**1,749**	**725**	**2,474**	**71%**	**29%**	**22,468**	**20,706**	**290**	**0**	**12**	**1,498**	**1,133**	**2,694**	**224**	**1,035**	**149,185**	**2,676**	**0**	**0.9**	**725**	**3,952**	**5.4**	**0.3**	**1.1**	**158**

FORTIS BC

2010 Residential Programs	PROGRAM: COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Partners Incentives	Partners Administration	Partners Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) Gross	Net-to-Gross	Net	LIFE Years
FEI															
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
Energy STAR Heating System Upgrade _Terasen (Retrofit)	962	51	1,013	0	0	0	1,316	2,329	43%	0%	57%	42,713	57%	24,346	18
Energy STAR Heating System Upgrade _Live Smart BC (Retrofit)	1,372	0	1,372	0	0	0	1,877	3,249	42%	0%	58%	60,928	57%	34,729	18
EnerChoice Fireplaces (Retrofit)	16	40	56	0	0	0	0	56	100%	0%	0%	850	76%	646	15
ENERGY STAR Hot Water Heaters (Retrofit)	15	52	67	0	0	0	6	73	92%	0%	8%	304	80%	243	13
TLC	320	112	432	0	0	0	0	432	100%	0%	0%	0	100%	0	1
2010 Total Residential	2,686	254	2,940	-	-	-	3,199	6,139	48%	-	52%	104,795		59,965	

2010 Residential Programs	ALTERNATE Impact: Energy MWh	Capacity kW	NET PRESENT VALUE: Levelized Cost ($/GJ)	Utility Benefits (Costs): Program ($'000s)	Alternate ($'000s)	Participant Benefits (Costs): Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings: Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST: Natural Gas Utility	Participant: Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
Energy STAR Heating System Upgrade _Terasen (Retrofit)	0	-	4	2,412	N/A	2,636	349	N/A	238,325	0	-	2.4	1,316	2,985	2.3	0.7	1.0	83
Energy STAR Heating System Upgrade _Live Smart BC (Retrofit)	0	-	4	3,441	N/A	3,760	499	N/A	339,960	0	-	2.5	1,877	4,258	2.3	0.7	1.1	191
EnerChoice Fireplaces (Retrofit)	0	-	10	57	N/A	63	8	N/A	5,746	0	-	1.0	-	71	N/A	0.5	1.0	1
ENERGY STAR Hot Water Heaters (Retrofit)	0	-	34	20	N/A	22	3	N/A	1,990	0	-	0.3	6	24	4.0	0.2	0.3	(53)
TLC	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
2010 Total Residential	0	-	5	5,929	0	6,480	859	0	586,021	-	-	2.0	3,199	7,339	2.3	0.6	1.0	(210)

FORTIS BC

2010 Residential Programs

FEVI

FEVI	PROGRAM: COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Partners – Incentives	Partners – Administration	Partners – Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) – Gross	Net-to-Gross	Net	LIFE – Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	2	12	14	0	0	0	1	15	95%	0%	5%	40	80%	32	13
EnerChoice Fireplaces (Retrofit)	4	11	15	0	0	0	0	15	100%	0%	0%	203	76%	154	15
ENERGY STAR Heating System Upgrade - Terasen (Retrofit)	27	11	38	0	0	0	36	74	51%	0%	49%	1,177	57%	671	18
ENERGY STAR Heating System Upgrade_LiveSmart BC (Retrofit)	48	0	48	0	0	0	66	114	42%	0%	58%	2,131	57%	1,215	18
TLC	36	42	79	0	0	0	0	79	100%	0%	0%	0	100%	0	1
Total Residential	117	76	193	-	-	-	103	296	65%	-	35%	3,551		2,072	

FEVI	ALTERNATE: Impact – Energy (MWh)	Impact – Capacity (kW)	NET PRESENT VALUE: Levelized Cost ($/GJ)	Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST: Natural Gas – Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas – Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	0	-	51	3	N/A	4	0	N/A	269	0	-	0.2	1	4	5.6	0.1	0.2	(12)
EnerChoice Fireplaces (Retrofit)	2	-	10	14	2	21	2	1	1,415	13	-	1.0	-	25	N/A	0.4	1.1	1
ENERGY STAR Heating System Upgrade - Terasen (Retrofit)	0	-	6	69	N/A	104	10	N/A	6,810	0	-	1.8	36	114	3.1	0.5	0.9	(5)
ENERGY STAR Heating System Upgrade_LiveSmart BC (Retrofit)	0	-	4	125	N/A	188	18	N/A	12,335	0	-	2.6	66	207	3.1	0.5	1.1	12
TLC	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Total Residential	2	-	9	212	2	318	31	1	20,830	13	-	1.1	103	350	3.4	0.4	0.7	(83)

FORTIS BC

	PROGRAM														
2010 Commercial Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
Commercial Energy Efficiency Programs															
New Construction															
Efficient Boiler Program	74	1	75	0	0	0	101	176	43%	0%	57%	3,207	82%	2,630	20
Light Comm. ENERGY STAR® Boiler Program	0	0	1	0	0	0	1	2	31%	0%	69%	111	82%	91	20
Retrofit															
Retrofit Efficient Boiler Program	1,189	23	1,213	0	0	0	1,610	2,823	43%	0%	57%	44,880	82%	36,802	20
Retrofit Light Comm. ENERGY STAR® Boiler Program	90	5	95	0	0	0	325	420	23%	0%	77%	7,696	82%	6,311	20
Retrofit Efficient Commercial Water Heater	15	3	19	0	0	0	21	40	47%	0%	53%	623	95%	592	12
Fireplace timer pilot program	10	0	10	0	0	0	0	10	100%	0%	0%	585	100%	585	5
Retrofit Energy Assesment	66	25	91	0	0	0	0	91	100%	0%	0%	26,840	65%	17,446	1
PSECA	519	25	543	0	0	0	974	1,517	36%	0%	64%	18,222	100%	18,222	
2010											-				
Total Commercial	1,964	81	2,045	0	0	0	3,032	5,078	40%	0%	60%	102,164		82,678	

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
2010 Commercial Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant						
FEI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
Commercial Energy Efficiency Programs																		
New Construction																		
Efficient Boiler Program	0	-	3	277	N/A	282	40	N/A	27,055	0	-	3.7	101	322	3.2	0.8	1.6	101
Light Comm. ENERGY STAR® Boiler Program	0	-	1	10	N/A	10	1	N/A	936	0	-	15.6	1	11	8.1	0.9	4.8	8
Retrofit			-											-				
Retrofit Efficient Boiler Program	0	-	3	3,872	N/A	3,951	554	N/A	378,622	0	-	3.2	1,610	4,505	2.8	0.7	1.4	1,049
Retrofit Light Comm. ENERGY STAR® Boiler Program	0	-	1	664	N/A	678	95	N/A	64,926	0	-	7.0	325	773	2.4	0.9	1.6	244
Retrofit Efficient Commercial Water Heater	0	-	4	45	N/A	46	7	N/A	4,607	0	-	2.4	21	53	2.5	0.7	1.1	5
Fireplace timer pilot program	0	-	4	23	N/A	23	4	N/A	2,374	0	-	2.3	-	27	N/A	0.7	2.3	13
Retrofit Energy Assesment	0	-	6	215	N/A	154	35	N/A	16,247	0	-	2.4	-	189	N/A	0.9	2.4	124
PSECA	1,768	-	3	1,634	2,061	1,676	241	1,321	163,420	17,177	-	3.0	974	3,237	3.3	0.7	2.4	2,179
2010														-				
Total Commercial	1,768	-	3	6,739	2,061	6,820	976	1,321	658,188	17,177	0	3.3	3,032	9,117	3.0	0.8	1.7	3,723

FORTIS BC

	PROGRAM															ALTERNATE	
2010 Commercial Programs	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact	
FEVI	Utility			Partners											Years	Energy	Capacity
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program	Program	Program
2010																	
Commercial Energy Efficiency Programs																	
New Construction																	
Efficient Boiler Program	6	1	6	0	0	0	3	10	67%	0%	33%	125	82%	103	20	1	-
Retrofit																	
Efficient Boiler Program	97	5	103	0	0	0	148	251	41%	0%	59%	3,560	82%	2,919	18	7	-
Light Comm. ENERGY STAR® Boiler Program	12	1	13	0	0	0	49	62	21%	0%	79%	788	82%	646	20	0	-
Retrofit Efficient Commercial Water Heater Program	3	1	4	0	0	0	9	12	30%	0%	70%	152	95%	144	12	0	-
Spray N'Save	12	4	16	0	0	0	0	16	100%	0%	0%	1,746	88%	1,536	5	0	-
Retrofit Energy Assesment Program	16	2	17	0	0	0	0	17	100%	0%	0%	6,344	65%	4,124	1	0	-
PSECA	291	6	298	0	0	0	414	711	42%	0	58%	11,706	100%	11,706		274	0
Total Commercial	437	20	456	0	0	0	623	1,079	42%		58%	24,421		21,178		282	0

	NET PRESENT VALUE									BENEFIT/COST						
2010 Commercial Programs	Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEVI	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																
Commercial Energy Efficiency Programs																
New Construction																
Efficient Boiler Program	6	11	1	20	2	1	1,097	8	-	1.8	3	22	7.0	0.4	1.3	3
Retrofit																
Efficient Boiler Program	3	301	7	535	44	5	29,642	59	-	2.9	148	584	3.9	0.5	1.2	58
Light Comm. ENERGY STAR® Boiler Program	2	71	N/A	126	10	N/A	6,915	0	-	5.5	49	136	2.8	0.5	1.2	9
Retrofit Efficient Commercial Water Heater Program	3	11	N/A	21	2	N/A	1,155	0	-	3.0	9	22	2.6	0.5	0.9	(1)
Spray N'Save	2	61	N/A	110	10	N/A	6,322	0	-	3.9	-	120	N/A	0.5	3.9	45
Retrofit Energy Assesment Program	5	51	N/A	66	8	N/A	3,859	0	-	2.9	-	74	N/A	0.6	2.9	34
PSECA	3	1,067	307	1,937	160	212	107,935	2,559	0	3.6	414	2,308	5.6	0.5	1.9	663
Total Commercial	3	1,574	315	2,814	235	217	156,925	2,626	0	3.4	623	3,266	5.2	0.5	1.8	810

FORTIS BC

	PROGRAM														
2010 Joint Initiatives Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
Tier 3 ENERGY STAR Washer / Dryer Rebates	7	0	7	0	0	0	29	36	18%	0%	82%	364	90%	328	14
Water Savers Pilot	8	7	14	0	0	0	0	14	100%	0%	0%	500	84%	420	10
EcoEnergy Audits		349	349					349							
City of Vancouver Weatherization		15	15					15							
Total Residential	14	371	385	-	-	-	29	414	93%	-	7%	864		748	

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
2010 Joint Initiatives Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
Tier 3 ENERGY STAR Washer / Dryer Rebates	0	-	2	28	N/A	30	4	N/A	2,801	0	-	4.3	29	35	1.2	0.8	0.8	(8)
Water Savers Pilot	0	-	5	28	N/A	31	4	N/A	2,899	0	-	2.0	-	35	N/A	0.6	2.0	14
EcoEnergy Audits																		
City of Vancouver Weatherization																		
Total Residential	0	-	67	56	0	61	8	0	5,700	0	0	0.1	29	70	2.4	0.1	0.1	(358)

FORTIS BC

	PROGRAM														
2010 Joint Initiatives Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEVI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
EcoEnergy D-Visit Rebates	15	1	16	0	0	0	0	16	100%	0%	0%	0	100%	0	0
Total Residential	15	1	16	0	0	0	0	16	100%	-	0%	0		0	

	ALTERNATE		NET PRESENT VALUE								
2010 Joint Initiatives Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings		
FEVI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)
2010											
RESIDENTIAL:											
EcoEnergy D-Visit Rebates	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-
Total Residential	0	-	LB	0	0	0	0	0	-	-	-

	BENEFIT/COST						
2010 Joint Initiatives Programs		Participant					
FEVI	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010							
RESIDENTIAL:							
EcoEnergy D-Visit Rebates	LB	-	-	N/A	N/A	LB	LB
Total Residential	LB	-	-	N/A	N/A	LB	LB

FORTIS BC

	PROGRAM														
2010 Conservation for Affordable Housing Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
Energy Savings Kits	39	44	83	0	0	0	0	83	100%	0%	0%	3,613	73%	2,637	8
REnEW	0	148	148	0	0	0	0	148	100%	0%	0%	0	100%	0	0
SEMP Study	0	14	14	0	0	0	0	14	100%	0%	0%	0	100%	0	0
Mobile Homes Study	0	8	8	0	0	0	0	8	100%	0%	0%	0	100%	0	0
Total Residential	39	213	253	0	0	0	0	253	100%	-	0%	3,613		2,637	

	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
2010 Conservation for Affordable Housing Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
Energy Savings Kits	0	-	5	194	N/A	164	24	N/A	15,520	0	-	2.3	-	187	N/A	0.8	2.3	111
REnEW	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
SEMP Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Mobile Homes Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Total Residential	0	0	16	194	LB	164	24	LB	15,520	LB	LB	0.8	-	187	N/A	0.5	0.8	(59)

FORTIS BC

	PROGRAM														
2010 Conservation for Affordable Housing Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEVI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
ESK	10	11	21	0	0	0	0	21	100%	0%	0%	904	73%	660	8
Mobile Home Study	0	2	2	0	0	0	0	2	100%	0%	0%	0	100%	0	0
Strategic Energy Management Plan	0	3	3	0	0	0	0	3	100%	0%	0%	0	100%	0	0
Total Residential	10	16	26	0	0	0	0	26	100%	-	0%	904		660	

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
2010 Conservation for Affordable Housing Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant						
FEVI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
ESK	0	-	5	50	N/A	59	6	N/A	3,959	0	-	2.4	-	65	N/A	0.6	2.4	29
Mobile Home Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Strategic Energy Management Plan	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Total Residential	0	0	7	50	N/A	59	6	N/A	3,959	N/A	N/A	1.9	-	65	N/A	0.6	1.9	23

FORTIS BC

2010 High Carbon Fuel Switching Programs

FEI

	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
Innovative Technologies															
NGV Vehicles (Kelowna School Bus)	363	1	364	-	-	-	-	364	100%	-	0%	(4,312)	100%	(4,312)	15
NGV Vehicles (Surrey)	27	1	27	-	-	-	-	27	100%	-	0%	(1,538)	100%	(1,538)	8
NGV Vehicles (Waste Management Inc.)	804	1	804	-	-	-	-	804	100%	-	0%	(21,140)	100%	(21,140)	10
Solar Water heating PSECA Program	229	-	229	264	-	264	958	1,451	16%	0	66%	2,579	100%	2,579	25
LNG (Vedder)	4,393	1	4,394	-	-	-	-	4,394	100%	-	0%	(138,500)	100%	(138,500)	5
Total Residential	5,816	2	5,818	264	-	264	958	7,040		0	14%	(162,911)		(162,911)	

	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	L	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
Innovative Technologies																		
NGV Vehicles (Kelowna School Bus)	95	-	FS	(377)	834	(418)	(57)	834	(38,348)	927	-	FS	475	834	1.8	0.6	1.1	93
NGV Vehicles (Surrey)	34	-	FS	(86)	190	(95)	(14)	190	(9,050)	211	-	FS	109	190	1.7	0.8	1.7	76
NGV Vehicles (Waste Management Inc.)	468	-	FS	(1,404)	3,100	(1,554)	(218)	3,100	(145,905)	3,445	-	FS	1,773	3,100	1.7	0.7	1.4	892
Solar Water heating PSECA Program	-	-	8	300	-	329	42	-	29,053	-	-	1.3	958	372	0.4	0.5	0.2	(1,152)
LNG (Vedder)	3,583	-	FS	(5,369)	13,583	(5,828)	(882)	13,583	(562,146)	15,092	-	FS	6,710	13,583	2.0	0.6	1.4	3,820
Total Residential	4,180	-	FS	(6,937)	17,707	(7,567)	(1,128)	17,707	(726,396)	19,675	-	FS	9,653	17,707	1.8	0.6	1.3	3,730

FORTIS BC

	PROGRAM														
2010 Innovative Technologies Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEVI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
Solar Water heating PSECA Program TGVI	143	0	143	162	0	162	491	796	18%	20%	62%	1,683	100%	1,683	25
Total Commercial	143	0	143	162	0	162	491	796	18%	0	62%	1,683		1,683	

	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
2010 Innovative Technologies Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEVI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
RESIDENTIAL:																		
Solar Water heating PSECA Program TGVI	0	-	7	209	N/A	364	29	N/A	19,845	0	-	1.5	491	393	0.8	0.4	0.3	(587)
Total Commercial	0	0	7	209	0	364	29	0	19,845	0	0	1.5	491	393	0.8	0.4	0.3	(587)

FORTIS BC

2010 High Carbon Fuel Switching Programs	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
FEI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
Residential															
Switch 'N' Shrink High Carbon Fuel Switching	29	46	75	-	-	-	-	75	100%	-	0%	(1,247)	50%	(624)	18
Total Residential	29	46	75	-	-	-	-	75		-	0%	(1,247)		(624)	

2010 High Carbon Fuel Switching Programs	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	L	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																		
Residential																		
Switch 'N' Shrink High Carbon Fuel Switching	1	-	FS	(61)	159	(67)	(9)	159	(6,103)	7	-	FS	76	159	2.1	0.5	1.2	23
Total Residential	1	-	FS	(61)	159	(67)	(9)	159	(6,103)	7	-	FS	76	159	2.1	0.5	1.2	23

FORTIS BC

2010 High Carbon Fuel Switching

FEVI

	PROGRAM – COSTS ($000) – Utility Incentives	Utility Administration	Utility Total	Partners Incentives	Partners Administration	Partners Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) Gross	Net-to-Gross	Net	LIFE Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2010															
RESIDENTIAL:															
Switch 'N' Shrink High Carbon Fuel Switching	149	76	225	0	0	0	0	225	100%	0%	0%	(6,407)	50%	(3,204)	18
Total Residential	149	76	225	-	-	-	0	225	100%	-	0%	(6,407)		(3,204)	

	ALTERNATE Impact Energy MWh	Impact Capacity kW	NET PRESENT VALUE Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Participant Benefits (Costs) Carbon Tax ($'000s)	Participant Benefits (Costs) Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Program Net Savings Alternate Energy (MWh)	Program Net Savings Alternate Capacity (kW)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)
2010											
RESIDENTIAL:											
Switch 'N' Shrink High Carbon Fuel Switching	7	-	FS	(337)	817	(497)	(48)	817	(32,529)	37	-
Total Residential	7	-	FS	(337)	817	(497)	(48)	817	(32,529)	37	-

	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010							
RESIDENTIAL:							
Switch 'N' Shrink High Carbon Fuel Switching	FS	545	817	1.5	0.9	1.5	255
Total Residential	FS	545	817	1.5	0.9	1.5	255

2011 DSM Planned

	PROGRAM: COSTS ($000) Utility Incentives	PROGRAM: COSTS ($000) Utility Administration	PROGRAM: COSTS ($000) Utility Total	PROGRAM: COSTS ($000) Participant	PROGRAM: COSTS ($000) Total	PROGRAM: COSTS ($000) % Utility	PROGRAM: COSTS ($000) % Participant	PROGRAM: SAVINGS (GJ) Gross	PROGRAM: SAVINGS (GJ) Net	ALTERNATE Impact: Energy MWh	ALTERNATE Impact: Capacity kW	Levelized Cost ($/GJ)	NET PRESENT VALUE: Utility Benefits (Costs) Program ($'000s)	NET PRESENT VALUE: Utility Benefits (Costs) Alternate ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs) Program ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs) Carbon Tax ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs) Alternate ($'000s)	NET PRESENT VALUE: Program Net Savings Natural Gas (GJ)	NET PRESENT VALUE: Program Net Savings Alternate Energy (MWh)	NET PRESENT VALUE: Program Net Savings Alternate Capacity (kW)	Benefits/cost test: Natural Gas Utility	Benefits/cost test: Participant Total Costs ($'000s)	Benefits/cost test: Participant Total Benefits ($'000s)	Benefits/cost test: Participant Benefit/Cost	Benefits/cost test: Natural Gas Rate Impact	Benefits/cost test: Total Resource	Benefits/cost test: TRC Net Benefits ($'000s)
2011 Planned																											
Residential Energy Efficiency Programs																											
2011 Residential Total	1,710	825	2,535	3	2,538	100%	0%	27,540	21,288	0	0	14	1,952	0	2,179	277	0	187,405	0	0	0.8	3	2,456	834.4	0.4	0.8	(586)
Commercial Energy Efficiency Programs																											
2011 Commercial Total	3,091	172	3,263	5,418	8,694	38%	62%	160,630	133,090	(1,281)	0	3	12,318	(1,764)	12,684	1,694	(1,130)	1,144,830	(14,697)	0	3.8	5,418	13,248	2.4	0.8	1.2	1,860
Joint Initiatives																											
2011 Joint Initiatives Total	2,678	605	3,283	7,090	10,372	32%	68%	98,163	87,916	0	0	4	9,652	0	10,019	1,322	0	901,538	0	0	2.9	7,090	11,341	1.6	0.7	0.9	(720)
Conservation for Affordable Housing Programs																											
2011 Affordable Housing Total	1,462	1,109	2,571	0	2,571	100%	0%	16,087	13,519	231	0	24	1,381	391	1,168	160	207	105,500	2,504	0	0.5	-	1,535	N/A	0.4	0.7	(799)
Innovative Technology																											
2011 Innotative Technology Total	3,931	124	4,055	603	4,851	84%	12%	(225,928)	(225,928)	5,771	2	FS	(13,502)	32,739	(13,206)	(2,047)	36,377	(1,349,902)	36,377	26	FS	15,856	36,377	2.3	0.8	1.8	14,387
High carbon fuel switching																											
2011 High Carbon Fuel Switching Total	420	104	524	0	524	100%	0	(17,200)	(8,600)	18	0	FS	(917)	2,529	(1,253)	(128)	2,529	(86,875)	100	0	FS	1,381	2,529	1.8	0.9	1.8	1,088
Portfolio Level Expenditure																											
2011 Portfolio Level Total		10,669																									
2011 TOTAL	**13,292**	**13,607**	**26,900**	**13,114**	**40,218**	**67%**	**33%**	**59,292**	**21,286**	**4,740**	**2**	**30**	**10,884**	**33,895**	**11,590**	**1,279**	**37,983**	**902,497**	**24,283**	**26**	**0.4**	**13,114**	**50,852**	**3.9**	**0.3**	**1.1**	**4,561**

FORTIS BC

2011 FEI Programs Planned	PROGRAM									ALTERNATE		NET PRESENT VALUE									Benefit/cost test						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2011																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	1,373	375	1,748	(23)	1,724	101%	-1%	22,032	17,030	0	-	12	1,556	0	1,605	221	0	149,446	-	-	0.9	-	1,849	N/A	0.5	0.9	(168)
Non Program Specific Admin Cost		314																									
2011 Residential Total	**1,373**	**689**	**2,062**	**(23)**	**2,038**	**101%**	**-1%**	**22,032**	**17,030**	**0**	**-**	**12**	**1,556**	**-**	**1,605**	**221**	**-**	**149,446**	**-**	**-**	**0.8**	**-**	**1,849**	**N/A**	**0.4**	**0.8**	**(482)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	2,701	108	2,809	4,572	7,391	38%	62%	141,022	117,077	(1,281)	-	3	10,862	(1,764)	10,454	1,510	(1,130)	1,021,668	(14,697)	-	3.9	4,572	10,834	2.4	0.8	1.2	1,707
Non Program Specific Admin Cost		**30**																									
2011 Commercial Total	**2,701**	**138**	**2,839**	**4,572**	**7,421**	**38%**	**62%**	**141,022**	**117,077**	**(1,281)**	**-**	**3**	**10,862**	**(1,764)**	**10,454**	**1,510**	**(1,130)**	**1,021,668**	**(14,697)**	**-**	**3.8**	**4,572**	**10,834**	**2.4**	**0.8**	**1.2**	**1,677**
Joint Initiatives																											
Energy Efficiency Program	2,428	354	2,732	6,354	9,137	30%	70%	88,536	79,180	0	0	3	8,729	0	8,934	1,194	0	814,827	0	0	3.2	6,354.4	10,128	1.6	0.7	1.0	(407)
Non Program Specific Admin Cost		160																									
2011 Joint Initiatives Total	**2,428**	**514**	**2,942**	**6,354**	**9,297**	**32%**	**68%**	**88,536**	**79,180**	**0**	**0**	**3**	**8,729**	**0**	**8,934**	**1,194**	**0**	**814,827**	**0**	**0**	**3.0**	**6,354**	**10,128**	**1.6**	**0.7**	**0.9**	**(567)**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	1,170	881	2,051	0	2,051	100%	0%	12,870	10,816	185	0	24	1,107	312	908	128	166	84,514	2,003	0	0.5	0.0	1,202	0.0	0.4	0.7	(631)
Non Program Specific Admin Cost		7																									
2011 Affordable Housing Total	**1,170**	**888**	**2,058**	**0**	**2,058**	**100%**	**0%**	**12,870**	**10,816**	**185**	**0**	**32**	**1,107**	**312**	**908**	**128**	**166**	**84,514**	**2,003**	**0**	**0.5**	**-**	**1,202**	**N/A**	**0.4**	**0.7**	**(638)**
Innovative Technology																											
Energy Efficiency Program	3,926	29	3,955	600	4,715	84%	13%	(225,989)	(225,989)	5,771	2	FS	(13,509)	32,739	(13,219)	(2,048)	4,938	(1,350,618)	36,377	26	FS	15,867	4,938	0.3	0.8	1.8	14,515
Non Program Specific Admin Cost		85																									
2010 Innovative Technology Total	**3,926**	**114**	**4,040**	**600**	**4,800**	**84%**	**13%**	**(225,989)**	**(225,989)**	**5,771**	**2**	**FS**	**(13,509)**	**32,739**	**(13,219)**	**(2,048)**	**4,938**	**(1,350,618)**	**36,377**	**26**	**FS**	**15,867**	**4,938**	**0.3**	**0.8**	**1.8**	**14,430**
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	100	21	121	0	121	100%	0%	(3,440)	(1,720)	4	0	FS	(178)	506	(186)	(25)	506	(17,116)	20	0	FS	211.2	506	2.4	0.6	1.7	207
Non Program Specific Admin Cost		0																									
2011 High Carbon Fuel Switching Total	**100**	**21**	**121**	**0**	**121**	**100%**	**0%**	**(3,440)**	**(1,720)**	**4**	**0**	**FS**	**(178)**	**506**	**(186)**	**(25)**	**506**	**(17,116)**	**20**	**0**	**FS**	**211**	**506**	**2.4**	**0.6**	**1.7**	**207**
Portfolio level expenditure																											
Conservation Education & Outreach		2,890																									
Enabling activities		1,776																									
DSMS consultant costs		304																									
Industrial Program costs		1,875																									
Labor		2,168																									
TGI Portfolio level total		**9,013**																									
2011 Total	**11,698**	**11,376**	**23,074**	**11,503**	**34,747**	**66%**	**33%**	**35,031**	**(3,606)**	**4,679**	**2**	**32.8**	**8,566**	**31,794**	**8,495**	**981**	**4,479**	**702,719**	**23,702**	**26**	**0.4**	**11,503**	**13,955**	**1.2**	**0.3**	**1.1**	**5,613**

FORTIS BC VANCOUVER ISLAND

2011 FEVI Programs Planned	PROGRAM: COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) Gross	Net	ALTERNATE Impact Energy MWh	Capacity kW	NET PRESENT VALUE Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2011																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	337	96	433	26	459	94%	6%	5,508	4,258	0	0	11	396	0	575	56	0	37,959	0	0	0.9	26	631	24.0	0.4	0.9	(64)
Non Program Specific Admin Cost		40																									
2011 Residential Total	**337**	**136**	**473**	**26**	**499**	**94%**	**6%**	**5,508**	**4,258**	**0**	**0**	**11**	**396**	**0**	**575**	**56**	**0**	**37,959**	**0**	**0**	**0.8**	**26**	**631**	**24.0**	**0.4**	**0.8**	**(104)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	391	24	415	846	1,263	33%	67%	19,608	16,013	0	0	3	1,456	0	2,230	184	0	123,163	0	0	3.5	846	2,414	2.9	0.6	1.2	193
Non Progam Specific Admin Cost		10																									
2011 Commercial Total	**391**	**34**	**425**	**846**	**1,273**	**33%**	**67%**	**19,608**	**16,013**	0	0	**3**	**1,456**	**0**	**2,230**	**184**	**0**	**123,163**	**0**	**0**	**3.4**	**846**	**2,414**	**2.9**	**0.5**	**1.1**	**183**
Joint Initiatives																											
Energy Efficiency Program	249	51	300	735	1,036	29%	71%	9,627	8,736	0	0	3	923	0	1,085	127	0	86,712	0	0	3.1	735	1,212	1.6	0.7	0.9	(113)
Non Progam Specific Admin Cost		40																									
2011 Joint Initiatives Total	**249**	**91**	**340**	**735**	**1,076**	**29%**	**71%**	**9,627**	**8,736**	**0**	**0**	**3**	**923**	**0**	**1,085**	**127**	**0**	**86,712**	**0**	**0**	**2.7**	**735**	**1,212**	**1.6**	**0.6**	**0.9**	**(153)**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	292	218	510	0	510	100%	0%	3,217	2,704	46	0	24	275	78	260	32	41	20,986	501	0	0.5	0	333	0.0	0.4	0.7	(157)
Non Program Specific Admin Cost		3																									
2011 Affortable Housing Total	**292**	**221**	**513**	**0**	**513**	**100%**	**0%**	**3,217**	**2,704**	**46**	**0**	**21**	**275**	**78**	**260**	**32**	**41**	**20,986**	**501**	**0**	**0.5**	**0**	**333**	**0.0**	**0.4**	**0.7**	**(160)**
Innovative Technology																											
Energy Efficiency Program	5	0	5	3	41	12%	8%	61	61	0	0	7	8	0	13	1	0	716	0	0	1.6	3	14	4.5	0.4	0.2	(33)
Non Program Specific Admin Cost		10																									
2010 Innovative Technology Total	**5**	**10**	**15**	**3**	**51**	**29%**	**6%**	**61**	**61**	**0**	**0**	**7**	**8**	**0**	**13**	**1**	**0**	**716**	**0**	**0**	**0.5**	**3**	**14**	**4.5**	**0.3**	**0.2**	**(43)**
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	320	83	403	0	403	100%	0%	(13,760)	(6,880)	15	0	FS	(739)	2,023	(1,067)	(103)	2,023	(69,759)	80	0	FS	1,170	2,023	1.7	0.9	1.8	881
Non Progam Specific Admin Cost		0																									
2011 High Carbon Fuel Switching Total	**320**	**83**	**403**	**0**	**403**	**100%**	**0%**	**(13,760)**	**(6,880)**	**15**	**0**	**FS**	**(739)**	**2,023**	**(1,067)**	**(103)**	**2,023**	**(69,759)**	**80**	**0**	**FS**	**1,170**	**2,023**	**1.7**	**0.9**	**1.8**	**881**
Portfolio level expenditure																											
Conservation Education & Outreach		648																									
Enabling Activities		390																									
DSMS consultant costs		76																									
Industrial Program Costs		0																									
Labor Costs		542																									
TGVI Portfolio level total		**1,656**																									
2011 Planned Total	**1,595**	**2,230**	**3,825**	**1,611**	**5,472**	**70%**	**29%**	**24,261**	**24,892**	**61**	**0**	**19**	**2,318**	**2,101**	**3,096**	**298**	**2,065**	**199,777**	**580**	**0**	**1**	**1,611**	**5,458**	**3**	**0**	**0.8**	**(1,052)**

2011 DSM Planned

	PROGRAM									ALTERNATE		NET PRESENT VALUE									Benefits/cost test						
	COSTS ($000)							SAVINGS (GJ)		Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings			Participant						
	Utility									Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Participant	Total	% Utility	% Participant	Gross	Net	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
2011 Planned																											
Residential Energy Efficiency Programs																											
2011 Residential Total	1,710	825	2,535	3	2,538	100%	0%	27,540	21,288	0	0	14	1,952	0	2,179	277	0	187,405	0	0	0.8	3	2,456	834.4	0.4	0.8	(586)
Commercial Energy Efficiency Programs																											
2011 Commercial Total	3,091	172	3,263	5,418	8,694	38%	62%	160,630	133,090	(1,281)	0	3	12,318	(1,764)	12,684	1,694	(1,130)	1,144,830	(14,697)	0	3.8	5,418	13,248	2.4	0.8	1.2	1,860
Joint Initiatives																											
2011 Joint Initiatives Total	2,678	605	3,283	7,090	10,372	32%	68%	98,163	87,916	0	0	4	9,652	0	10,019	1,322	0	901,538	0	0	2.9	7,090	11,341	1.6	0.7	0.9	(720)
Conservation for Affordable Housing Programs																											
2011 Affordable Housing Total	1,462	1,109	2,571	0	2,571	100%	0%	16,087	13,519	231	0	24	1,381	391	1,168	160	207	105,500	2,504	0	0.5	-	1,535	N/A	0.4	0.7	(799)
Innovative Technology																											
2011 Innotative Technology Total	0	0	0	0	0	#DIV/0!	#DIV/0!	0	0	0	0	-	0	0	0	0	0	0	0	0	N/A	-	-	N/A	N/A	N/A	0
High carbon fuel switching																											
2011 High Carbon Fuel Switching Total	420	104	524	0	524	100%	0	(17,200)	(8,600)	18	0	FS	(917)	2,529	(1,253)	(128)	2,529	(86,875)	100	0	FS	1,381	2,529	1.8	0.9	1.8	1,088
Portfolio Level Expenditure																											
2011 Portfolio Level Total		10,669																									
2011 TOTAL	**9,361**	**13,483**	**22,845**	**12,511**	**35,367**	**65%**	**35%**	**285,220**	**247,214**	**(1,032)**	**0**	**10**	**24,386**	**1,156**	**24,796**	**3,326**	**1,606**	**2,252,399**	**(12,094)**	**0**	**1.1**	**12,511**	**29,728**	**2.4**	**0.5**	**0.7**	**(9,825)**

FORTIS BC

2011 DSM Planned

2011 FEI Programs Planned	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Participant	Total	% Utility	% Participant	SAVINGS (GJ) – Gross	SAVINGS (GJ) – Net	ALTERNATE Impact – Energy (MWh)	ALTERNATE Impact – Capacity (kW)	Levelized Cost ($/GJ)	NET PRESENT VALUE – Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	Benefit/cost test – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
2011																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	1,373	375	1,748	(23)	1,724	101%	-1%	22,032	17,030	0	-	12	1,556	0	1,605	221	0	149,446	-	-	0.9	-	1,849	N/A	0.5	0.9	(168)
Non Program Specific Admin Cost		314																									
2011 Residential Total	**1,373**	**689**	**2,062**	**(23)**	**2,038**	**101%**	**-1%**	**22,032**	**17,030**	**0**	**-**	**12**	**1,556**	**-**	**1,605**	**221**	**-**	**149,446**	**-**	**-**	**0.8**	**-**	**1,849**	**N/A**	**0.4**	**0.8**	**(482)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	2,701	108	2,809	4,572	7,391	38%	62%	141,022	117,077	(1,281)	-	3	10,862	(1,764)	10,454	1,510	(1,130)	1,021,668	(14,697)	-	3.9	4,572	10,834	2.4	0.8	1.2	1,707
Non Program Specific Admin Cost		**30**																									
2011 Commercial Total	**2,701**	**138**	**2,839**	**4,572**	**7,421**	**38%**	**62%**	**141,022**	**117,077**	**(1,281)**	**-**	**3**	**10,862**	**(1,764)**	**10,454**	**1,510**	**(1,130)**	**1,021,668**	**(14,697)**	**-**	**3.8**	**4,572**	**10,834**	**2.4**	**0.8**	**1.2**	**1,677**
Joint Initiatives																											
Energy Efficiency Program	2,428	354	2,732	6,354	9,137	30%	70%	88,536	79,180	0	0	3	8,729	0	8,934	1,194	0	814,827	0	0	3.2	6,354.4	10,128	1.6	0.7	1.0	(407)
Non Program Specific Admin Cost		160																									
2011 Joint Initiatives Total	**2,428**	**514**	**2,942**	**6,354**	**9,297**	**32%**	**68%**	**88,536**	**79,180**	**0**	**0**	**3**	**8,729**	**0**	**8,934**	**1,194**	**0**	**814,827**	**0**	**0**	**3.0**	**6,354**	**10,128**	**1.6**	**0.7**	**0.9**	**(567)**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	1,170	881	2,051	0	2,051	100%	0%	12,870	10,816	185	0	24	1,107	312	908	128	166	84,514	2,003	0	0.5	0.0	1,202	0.0	0.4	0.7	(631)
Non Program Specific Admin Cost		7																									
2011 Affordable Housing Total	**1,170**	**888**	**2,058**	**0**	**2,058**	**100%**	**0%**	**12,870**	**10,816**	**185**	**0**	**32**	**1,107**	**312**	**908**	**128**	**166**	**84,514**	**2,003**	**0**	**0.5**	**-**	**1,202**	**N/A**	**0.4**	**0.7**	**(638)**
Innovative Technology																											
Energy Efficiency Program																											
Non Program Specific Admin Cost																											
2010 Innovative Technology Total																											
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	100	21	121	0	121	100%	0%	(3,440)	(1,720)	4	0	FS	(178)	506	(186)	(25)	506	(17,116)	20	0	FS	211.2	506	2.4	0.6	1.7	207
Non Program Specific Admin Cost		0																									
2011 High Carbon Fuel Switching Total	**100**	**21**	**121**	**0**	**121**	**100%**	**0%**	**(3,440)**	**(1,720)**	**4**	**0**	**FS**	**(178)**	**506**	**(186)**	**(25)**	**506**	**(17,116)**	**20**	**0**	**FS**	**211**	**506**	**2.4**	**0.6**	**1.7**	**207**
Portfolio level expenditure																											
Conservation Education & Outreach		2,890																									
Enabling activities		1,776																									
DSMS consultant costs		304																									
Industrial Program costs		1,875																									
Labor		2,168																									
TGI Portfolio level total		**9,013**																									
2011 Total	**7,772**	**11,262**	**19,034**	**10,903**	**29,947**	**64%**	**36%**	**261,020**	**222,383**	**(1,093)**	**0**	**9.3**	**22,076**	**(945)**	**21,714**	**3,029**	**(459)**	**2,053,338**	**(12,674)**	**0**	**1.2**	**10,903**	**24,284**	**2.2**	**0.5**	**0.7**	**(8,817)**

FORTIS BC VANCOUVER ISLAND

2011 DSM Planned

2011 FEVI Programs Planned	PROGRAM: COSTS ($000): Utility: Incentives	PROGRAM: COSTS ($000): Utility: Administration	PROGRAM: COSTS ($000): Utility: Total	PROGRAM: COSTS ($000): Participant	PROGRAM: COSTS ($000): Total	PROGRAM: COSTS ($000): % Utility	PROGRAM: COSTS ($000): % Participant	PROGRAM: SAVINGS (GJ): Gross	PROGRAM: SAVINGS (GJ): Net	ALTERNATE: Impact: Energy MWh	ALTERNATE: Impact: Capacity kW	NET PRESENT VALUE: Levelized Cost ($/GJ)	NET PRESENT VALUE: Utility Benefits (Costs): Program ($'000s)	NET PRESENT VALUE: Utility Benefits (Costs): Alternate ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs): Program ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs): Carbon Tax ($'000s)	NET PRESENT VALUE: Participant Benefits (Costs): Alternate ($'000s)	NET PRESENT VALUE: Program Net Savings: Natural Gas (GJ)	NET PRESENT VALUE: Program Net Savings: Alternate Energy (MWh)	NET PRESENT VALUE: Program Net Savings: Alternate Capacity (kW)	BENEFIT/COST: Natural Gas Utility	BENEFIT/COST: Participant: Total Costs ($'000s)	BENEFIT/COST: Participant: Total Benefits ($'000s)	BENEFIT/COST: Participant: Benefit/Cost	BENEFIT/COST: Natural Gas Rate Impact	BENEFIT/COST: Total Resource	BENEFIT/COST: TRC Net Benefits ($'000s)
2011																											
Residential Energy Efficiency Programs:																											
Energy Efficiency Program	337	96	433	26	459	94%	6%	5,508	4,258	0	0	11	396	0	575	56	0	37,959	0	0	0.9	26	631	24.0	0.4	0.9	(64)
Non Program Specific Admin Cost		40																									
2011 Residential Total	**337**	**136**	**473**	**26**	**499**	**94%**	**6%**	**5,508**	**4,258**	**0**	**0**	**11**	**396**	**0**	**575**	**56**	**0**	**37,959**	**0**	**0**	**0.8**	**26**	**631**	**24.0**	**0.4**	**0.8**	**(104)**
Commercial Energy Efficiency Programs:																											
Energy Efficiency Program	391	24	415	846	1,263	33%	67%	19,608	16,013	0	0	3	1,456	0	2,230	184	0	123,163	0	0	3.5	846	2,414	2.9	0.6	1.2	193
Non Progam Specific Admin Cost		10																									
2011 Commercial Total	**391**	**34**	**425**	**846**	**1,273**	**33%**	**67%**	**19,608**	**16,013**	0	0	**3**	**1,456**	**0**	**2,230**	**184**	**0**	**123,163**	**0**	**0**	**3.4**	**846**	**2,414**	**2.9**	**0.5**	**1.1**	**183**
Joint Initiatives																											
Energy Efficiency Program	249	51	300	735	1,036	29%	71%	9,627	8,736	0	0	3	923	0	1,085	127	0	86,712	0	0	3.1	735	1,212	1.6	0.7	0.9	(113)
Non Progam Specific Admin Cost		40																									
2011 Joint Initiatives Total	**249**	**91**	**340**	**735**	**1,076**	**29%**	**71%**	**9,627**	**8,736**	**0**	**0**	**3**	**923**	**0**	**1,085**	**127**	**0**	**86,712**	**0**	**0**	**2.7**	**735**	**1,212**	**1.6**	**0.6**	**0.9**	**(153)**
Conservation for Affordable Housing Programs																											
Energy Efficiency Program	292	218	510	0	510	100%	0%	3,217	2,704	46	0	24	275	78	260	32	41	20,986	501	0	0.5	0	333	0.0	0.4	0.7	(157)
Non Program Specific Admin Cost		3																									
2011 Affortable Housing Total	**292**	**221**	**513**	**0**	**513**	**100%**	**0%**	**3,217**	**2,704**	**46**	**0**	**21**	**275**	**78**	**260**	**32**	**41**	**20,986**	**501**	**0**	**0.5**	**0**	**333**	**0.0**	**0.4**	**0.7**	**(160)**
Innovative Technology																											
Energy Efficiency Program																											
Non Program Specific Admin Cost																											
2010 Innovative Technology Total																											
High Carbon Fuel Switching																											
High Carbon Fuel Switching Program	320	83	403	0	403	100%	0%	(13,760)	(6,880)	15	0	FS	(739)	2,023	(1,067)	(103)	2,023	(69,759)	80	0	FS	1,170	2,023	1.7	0.9	1.8	881
Non Progam Specific Admin Cost		0																									
2011 High Carbon Fuel Switching Total	**320**	**83**	**403**	**0**	**403**	**100%**	**0%**	**(13,760)**	**(6,880)**	**15**	**0**	**FS**	**(739)**	**2,023**	**(1,067)**	**(103)**	**2,023**	**(69,759)**	**80**	**0**	**FS**	**1,170**	**2,023**	**1.7**	**0.9**	**1.8**	**881**
Portfolio level expenditure																											
Conservation Education & Outreach		648																									
Enabling Activities		390																									
DSMS consultant costs		76																									
Industrial Program Costs		0																									
Labor Costs		542																									
TGVI Portfolio level total		**1,656**																									
2011 Planned Total	**1,590**	**2,220**	**3,810**	**1,608**	**5,420**	**70%**	**30%**	**24,200**	**24,831**	**61**	**0**	**19**	**2,310**	**2,101**	**3,082**	**297**	**2,065**	**199,060**	**580**	**0**	**1**	**1,608**	**5,444**	**3**	**0**	**0.8**	**(1,009)**

FORTIS BC

2011 Residential Planned	PROGRAM														
	COSTS ($000)											SAVINGS (GJ)			LIFE
FEI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2011															
RESIDENTIAL:															
EnerChoice Fireplaces (Retrofit)	576	117	693	0	0	0	(219)	474	146%	0%	-46%	14,880	76%	11,309	15
ENERGY STAR Hot Water Heaters (Retrofit)	429	138	567	0	0	0	195	762	74%	0%	26%	7,152	80%	5,722	13
TLC compaign	368	120	488	0	0	0	0	488	100%	0%	0%	0	100%	0	1
Total Residential	1,373	375	1,748	-	-	-	(23)	1,724	101%	-	-1%	22,032		17,030	

2011 Residential Planned	ALTERNATE		NET PRESENT VALUE									BENEFIT/COST						
	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																		
RESIDENTIAL:																		
EnerChoice Fireplaces (Retrofit)	0	-	7	1,065	N/A	1,098	151	N/A	102,031	0	-	1.5	-	1,468	N/A	0.6	2.2	591
ENERGY STAR Hot Water Heaters (Retrofit)	0	-	12	491	N/A	506	70	N/A	47,415	0	-	0.9	195	577	3.0	0.5	0.6	(271)
TLC compaign	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Total Residential	0	-	12	1,556	0	1,605	221	0	149,446	-	-	0.9	N/A	1,849	N/A	0.5	0.9	(168)

FORTIS BC

2011 Residential Planned

FEVI	PROGRAM COSTS ($000) Utility Incentives	Utility Administration	Utility Total	Partners Incentives	Partners Administration	Partners Total	Participant	Total	% Utility	% Partner	% Participant
Label	B	C	D	E	F	G	H	I	J	K	L
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I
2011											
RESIDENTIAL:											
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	101	40	141	0	0	0	81	222	64%	0%	36%
EnerChoice Fireplaces (Retrofit)	144	29	173	0	0	0	(55)	118	146%	0%	-46%
TLC	92	26	118	0	0	0	0	118	100%	0%	0%
2010											
Total Residential	337	96	433	-	-	-	26	459	94%	-	6%

FEVI	PROGRAM SAVINGS (GJ) Gross	Net-to-Gross	Net	LIFE Years	ALTERNATE Impact Energy MWh	ALTERNATE Impact Capacity kW	NET PRESENT VALUE Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Participant Benefits (Costs) Carbon Tax ($'000s)	Participant Benefits (Costs) Alternate ($'000s)
Label	M	N	O	P	Q	R	S	T	U	V	W	X
Source Sheet or Calculation	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)
2011												
RESIDENTIAL:												
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	1,788	80%	1,430	13	0	-	12	125	N/A	181	18	N/A
EnerChoice Fireplaces (Retrofit)	3,720	76%	2,827	15	0	-	7	271	N/A	393	38	N/A
TLC	0	100%	0	1	0	-	LB	LB	N/A	N/A	N/A	N/A
2010												
Total Residential	5,508		4,258		0	-	11	396	0	575	56	0

FEVI	NET PRESENT VALUE Program Net Savings Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011										
RESIDENTIAL:										
ENERGY STAR Domestic Hot Water Heaters (Retrofit)	12,030	0	-	0.9	81	199	2.5	0.4	0.6	(98)
EnerChoice Fireplaces (Retrofit)	25,930	0	-	1.6	-	486	N/A	0.5	2.3	153
TLC	-	0	-	LB	-	-	N/A	N/A	LB	LB
2010										
Total Residential	37,959	-	-	0.9	26	631	24.0	0.4	0.9	(64)

FORTIS BC

	PROGRAM															ALTERNATE	
2011 Commercial Programs Planned	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact	
FEI	Utility			Partners											Years	Energy	Capacity
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program	Program	Program
2011																	
<u>Commercial Energy Efficiency Programs</u>																	
<u>New Construction</u>																	
Efficient Boiler Program	197	2	200	0	0	0	269	469	43%	0%	57%	8,552	82%	7,013	20	0	-
Light Commercial Energy Star Boiler Program	14	1	15	0	0	0	50	65	23%	0%	77%	1,184	82%	971	20	0	-
Efficient Water Heater	7	2	8	0	0	0	9	17	47%	0%	53%	267	95%	254	20	0	-
Spray Valve	0	0	0	0	0	0	0	0	100%	0%	0%	36	88%	32	5	0	-
Retrofit																	
Retrofit Efficient Boiler Program	1,311	25	1,337	0	0	0	1,775	3,112	43%	0%	57%	49,470	82%	40,565	20	0	-
Light Energy Star Commercial Boiler Program	156	9	165	0	0	0	562	727	23%	0%	77%	13,320	82%	10,922	20	0	-
Retrofit Efficient Water Heater Program	99	9	108	0	0	0	136	244	44%	0%	56%	4,005	95%	3,805	20	0	-
Energy Assessment Program	73	27	100	0	0	0	0	100	100%	0%	0%	29,768	65%	19,349	1	0	-
Fireplace Timer	20	0	20	0	0	0	0	20	100%	0%	0%	1,200	100%	1,200	5	0	-
Retrofit Spray Valve	20	3	23	11	0	11	0	33	68%	32%	0%	2,115	88%	1,861	5	0	-
Radiant Tube Heater Pilot Program	3	7	10	0	0	0	11	21	46%	0%	54%	275	100%	275	20	0	-
PSECA	800	24	824	0	0	0	1,759	2,583	32%	0%	68%	30,830	100%	30,830	20	(1,281)	-
Total Commercial	2,701	108	2,809	11	-	11	4,572	7,391	38%	0	62%	141,022		117,077		(1,281)	-

	NET PRESENT VALUE									BENEFIT/COST						
2011 Commercial Programs Planned	Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																
<u>Commercial Energy Efficiency Programs</u>																
<u>New Construction</u>																
Efficient Boiler Program	3	784	N/A	753	108	N/A	73,434	0	-	3.9	269	861	3.2	0.8	1.7	316
Light Commercial Energy Star Boiler Program	1	109	N/A	104	15	N/A	10,167	0	-	7.4	50	119	2.4	0.9	1.7	44
Efficient Water Heater	3	21	N/A	27	4	N/A	2,656	0	-	2.5	9	31	3.4	0.6	1.2	3
Spray Valve	3	1	N/A	1	0	N/A	129	0	-	3.5	-	1	N/A	0.8	3.5	1
Retrofit																
Retrofit Efficient Boiler Program	3	4,537	N/A	4,356	622	N/A	424,785	0	-	3.4	1,775	4,978	2.8	0.8	1.5	1,425
Light Energy Star Commercial Boiler Program	1	1,222	N/A	1,173	168	N/A	114,375	0	-	7.4	562	1,340	2.4	0.9	1.7	495
Retrofit Efficient Water Heater Program	3	309	N/A	409	58	N/A	39,842	0	-	2.9	136	467	3.4	0.6	1.3	65
Energy Assessment Program	6	271	N/A	171	39	N/A	18,058	0	-	2.7	-	210	N/A	1.0	2.7	170
Fireplace Timer	4	51	N/A	47	8	N/A	4,901	0	-	2.5	-	55	N/A	0.8	2.5	31
Retrofit Spray Valve	3	79	N/A	73	12	N/A	7,601	0	-	3.5	-	85	N/A	0.8	2.4	46
Radiant Tube Heater Pilot Program	3	31	N/A	30	4	N/A	2,880	0	-	3.2	11	34	3.0	0.8	1.5	10
PSECA	3	3,448	(1,764)	3,310	473	(1,130)	322,840	(14,697)	-	4.2	1,759	2,653	1.5	0.8	0.7	(899)
Total Commercial	3	10,862	(1,764)	10,454	1,510	(1,130)	1,021,668	(14,697)	-	3.9	4,572	10,834	2.4	0.8	1.2	1,707

FORTIS BC

2011 Commercial Programs Planned	PROGRAM															ALTERNATE	
	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact	
FEVI	Utility			Partners											Years	Energy	Capacity
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program	Program	Program
2010																	
Commercial Energy Efficiency Programs																	
New Construction																	
Efficient Boiler Program	12	1	13	0	0	0	6	19	67%	0%	33%	250	82%	205	20	0	-
Efficient Commercial Water Heater	2	0	3	0	0	0	3	6	46%	0%	54%	89	95%	85	12	0	-
Retrofit																	
Efficient Boiler Program	110	6	115	0	0	0	167	282	41%	0%	59%	4,005	82%	3,284	20	0	-
Light Comm. ENERGY STAR® Boiler Program	29	3	32	0	0	0	122	154	21%	0%	79%	1,970	82%	1,615	20	0	-
Retrofit Efficient Commercial Water Heater Program	7	2	9	0	0	0	22	31	30%	0%	70%	380	95%	361	12	0	-
Retrofit Energy Assessment Program	17	2	19	0	0	0	0	19	100%	0%	0%	6,832	65%	4,441	1	0	-
Fireplace timer	2	0	2	0	0	0	0	2	100%	0%	0%	90	100%	90	5	0	-
Spray Valve Program	5	1	5	2	0	2	0	8	68%	32%	0%	495	88%	436	5	0	-
PSECA	208	9	216	0	0	0	526	742	29%	0%	71%	5,497		5,497		0	-
Total Commercial	391	24	415	2	-	2	846	1,263	33%	0%	67%	19,608		16,013		0	-

2011 Commercial Programs Planned	NET PRESENT VALUE										BENEFIT/COST						
	Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings					Participant					
FEVI	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2010																
Commercial Energy Efficiency Programs																
New Construction																
Efficient Boiler Program	6	23	N/A	40	3	N/A	2,190	0	-	1.8	6	43	6.8	0.4	1.2	4
Efficient Commercial Water Heater	4	7	N/A	12	1	N/A	676	0	-	2.7	3	13	4.3	0.5	1.2	1
Retrofit																
Efficient Boiler Program	3	376	N/A	638	51	N/A	35,091	0	-	3.3	167	690	4.1	0.5	1.3	93
Light Comm. ENERGY STAR® Boiler Program	2	185	N/A	314	25	N/A	17,261	0	-	5.8	122	339	2.8	0.5	1.2	30
Retrofit Efficient Commercial Water Heater Program	3	30	N/A	51	4	N/A	2,884	0	-	3.2	22	56	2.6	0.5	1.0	(1)
Retrofit Energy Assessment Program	5	62	N/A	71	9	N/A	4,155	0	-	3.3	-	80	N/A	0.7	3.3	43
Fireplace timer	5	4	N/A	6	1	N/A	370	0	-	2.0	-	7	N/A	0.5	2.0	2
Spray Valve Program	3	19	N/A	31	3	N/A	1,791	0	-	3.5	-	34	N/A	0.5	2.4	11
PSECA	4	751	N/A	1,066	86	N/A	58,745	0	-	3.5	526	1,153	2.2	0.6	1.0	9
Total Commercial	3	1,456	0	2,230	184	0	123,163	0	0	3.5	846	2,414	2.9	0.6	1.2	193

FORTIS BC

2011 Joint Initiatives Planned

PROGRAM – COSTS ($000)

FEI	Utility			Partners							
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant
Label	B	C	D	E	F	G	H	I	J	K	L
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I
2011											
RESIDENTIAL:											
Washing Machine Rebate	302	57	359	0	0	0	1,721	2,080	17%	0%	83%
Live Smart BC 2010-2011	531	85	616	-	-	-	1,768	2,384	26%	-	74%
Live Smart BC 2011-2012	1,596	162	1,758	-	-	-	2,865	4,622	38%	-	62%
Home Efficiency Web Portal	0	50	50	0	0	0	0	50	100%	0%	0%
Total Residential	2,428	354	2,732	-	-	-	6,354	9,137	30%	-	70%

PROGRAM – SAVINGS (GJ), LIFE; ALTERNATE; NET PRESENT VALUE

FEI	SAVINGS (GJ)			LIFE	ALTERNATE Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings		
	Gross	Net-to-Gross	Net	Years	Energy MWh	Capacity kW	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)
Label	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
Source Sheet or Calculation	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)
2011															
RESIDENTIAL:															
Washing Machine Rebate	18,120	95%	17,214	14	0	-	2	1,551	N/A	1,600	221	N/A	149,200	0	-
Live Smart BC 2010-2011	24,390	88%	21,463		0	-	3	2,532	0	2,586	342	0	234,273	-	-
Live Smart BC 2011-2012	46,026	88%	40,503		0	-	4	4,646	0	4,748	631	0	431,354	-	-
Home Efficiency Web Portal	0	100%	0	14	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-
Total Residential	88,536		79,180		0	-	3	8,729	0	8,934	1,194	0	814,827	-	-

BENEFIT/COST

FEI	Natural Gas	Participant			Natural Gas		TRC Net Benefits
	Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Rate Impact	Total Resource	($'000s)
Label	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011							
RESIDENTIAL:							
Washing Machine Rebate	4.3	1,721	1,821	1.1	0.8	0.7	(529)
Live Smart BC 2010-2011	4.1	1768	2928	1.7	0.8	1.1	148
Live Smart BC 2011-2012	2.6	2865	5380	1.9	0.7	1.0	23
Home Efficiency Web Portal	LB	-	-	N/A	N/A	LB	LB
Total Residential	3.2	6,354	10,128	1.6	0.7	1.0	(407)

FORTIS BC

2011 Joint Initiatives Programs Planned

PROGRAM — COSTS ($000)

FEVI	Utility Incentives	Utility Administration	Utility Total	Partners Incentives	Partners Administration	Partners Total	Participant	Total	% Utility	% Partner	% Participant
Label	B	C	D	E	F	G	H	I	J	K	L
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I
2011											
RESIDENTIAL:											
Washing Machine Rebate	63	8	71	0	0	0	359	430	17%	0%	83%
Live Smart BC 2010-2011	27	15	42	0	0	0	88	130	32%	-	68%
Live Smart BC 2011-2012	160	18	178	-	-	0	288	466	38%	0%	62%
Home Efficiency Web Portal	0	10	10	0	0	0	0	10	100%	0%	0%
Total Residential	249	51	300	-	-	-	735	1,036	29%	-	71%

PROGRAM — SAVINGS (GJ), LIFE; ALTERNATE; NET PRESENT VALUE

FEVI	SAVINGS (GJ) Gross	Net-to-Gross	Net	LIFE Years	ALTERNATE Impact Energy MWh	Capacity kW	Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)
Label	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA
Source Sheet or Calculation	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)
2011															
RESIDENTIAL:															
Washing Machine Rebate	3,780	95%	3,591	14	0	-	2	329	N/A	478	47	N/A	31,613	0	-
Live Smart BC 2010-2011	1,221	88%	1,075		0	-	4	127	N/A	129	17	N/A	11,731	0	-
Live Smart BC 2011-2012	4,625	88%	4,070		0	-	4	467	0	477	63	0	43,367	-	-
Home Efficiency Web Portal	0	100%	0	0	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-
Total Residential	9,627		8,736		0	-	3	923	0	1,085	127	0	86,712	-	-

BENEFIT/COST

FEVI	Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011							
RESIDENTIAL:							
Washing Machine Rebate	4.6	359	525	1.5	0.6	0.8	(101)
Live Smart BC 2010-2011	3.0	88	147	1.7	0.7	1.0	(3)
Live Smart BC 2011-2012	2.6	288	541	1.9	0.7	1.0	2
Home Efficiency Web Portal	LB	-	-	N/A	N/A	LB	LB
Total Residential	3.1	735	1,212	1.6	0.7	0.9	(113)

FORTIS BC

2011 Conservation for Affordable Housing Programs

FEI

PROGRAM	COSTS ($000) Utility Incentives	COSTS ($000) Utility Administration	COSTS ($000) Utility Total	COSTS ($000) Partners Incentives	COSTS ($000) Partners Administration	COSTS ($000) Partners Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) Gross	SAVINGS (GJ) Net-to-Gross	SAVINGS (GJ) Net	LIFE Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2011															
RESIDENTIAL:															
Energy Savings Kits	88	98	186	0	0	0	0	186	100%	0%	0%	7,216	73%	5,267	8
Mobile Homes Study	0	8	8	0	0	0	0	8	100%	0%	0%	0	0%	0	0
CHF CO-Ops Study	0	12	12	0	0	0	0	12	100%	0%	0%	0	0%	0	0
REnEW	0	150	150	0	0	0	0	150	100%	0%	0%	0	0%	0	0
ECAP	1,082	613	1,694	0	0	0	0	1,694	100%	0%	0%	5,654	98%	5,548	
Total Residential	1,170	881	2,051	0	0	0	0	2,051	100%	-	0%	12,870		10,816	

	ALTERNATE Impact Energy MWh	ALTERNATE Impact Capacity kW	NET PRESENT VALUE Levelized Cost ($/GJ)	Utility Benefits (Costs) Program ($'000s)	Utility Benefits (Costs) Alternate ($'000s)	Participant Benefits (Costs) Program ($'000s)	Participant Benefits (Costs) Carbon Tax ($'000s)	Participant Benefits (Costs) Alternate ($'000s)	Program Net Savings Natural Gas (GJ)	Program Net Savings Alternate Energy (MWh)	Program Net Savings Alternate Capacity (kW)	BENEFIT/COST Natural Gas Utility	Participant Total Costs ($'000s)	Participant Total Benefits ($'000s)	Participant Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
Energy Savings Kits	0	-	6	416	N/A	327	47	N/A	31,271	0	-	2.2	-	374	N/A	0.8	2.2	229
Mobile Homes Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
CHF CO-Ops Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
REnEW	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
ECAP	185	-	32	691	312	581	81	166	53,242	2,003	-	0.4	-	827	N/A	0.3	0.6	(691)
Total Residential	185	0	24	1,107	312	908	128	166	84,514	2,003	N/A	0.5	-	1,202	N/A	0.4	0.7	(631)

FORTIS BC

	PROGRAM														
2011 Conservation for Affordable Housing Programs	COSTS ($000)											SAVINGS (GJ)			LIFE
FEVI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2011															
RESIDENTIAL:															
Retrofit ESK	22	25	47	0	0	0	0	47	100%	0%	0%	1,804	73%	1,317	8
Mobile Homes Study	0	2	2	0	0	0	0	2	100%	0%	0%	0	0%	0	1
CHF CO-Ops	0	3	3	0	0	0	0	3	100%	0%	0%	0	0%	0	0
Energy Efficiency Specialist Certification	0	35	35	0	0	0	0	35	100%	0%	0%	0	0%	0	0
ECAP	270	153	424	0	0	0	0	424	100%	0%	0%	1,414	99%	1,387	
Total Residential	292	218	510	0	0	0	0	510	100%	-	0%	3,217		2,704	

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
2011 Conservation for Affordable Housing Programs	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant						
FEVI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																		
RESIDENTIAL:																		
Retrofit ESK	0	-	6	105	N/A	117	12	N/A	7,897	0	-	2.3	-	129	N/A	0.6	2.3	58
Mobile Homes Study	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
CHF CO-Ops	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
Energy Efficiency Specialist Certification	0	-	LB	LB	N/A	N/A	N/A	N/A	-	0	-	LB	-	-	N/A	N/A	LB	LB
ECAP	46	-	32	170	78	143	20	41	13,089	501	-	0.4	-	204	N/A	0.3	0.6	(176)
Total Residential	46	0	24	275	78	260	32	41	20,986	501	N/A	0.5	-	333	N/A	0.4	0.7	(157)

FORTIS BC

2011 Innovative Technologies Planned	PROGRAM															ALTERNATE		NET PRESENT VALUE									BENEFIT/COST							
	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	Utility			Partners											Years	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																																	
Commercial																																	
Solar Air Heating PSECA Program	73	1	74	0	0	0	422	496	15%	0%	85%	1,458	100%	1,458	30	0	-	4	193	N/A	188	26	N/A	17,817	0	-	2.6	422	213	0.5	0.7	0.4	(303)
NGV Vehicles (COV)	702	1	703	0	0	0	0	703	100%	0%	0%	(13,716)	100%	(13,716)	8	303	-	FS	(816)	1,695	(797)	(124)	105	(81,428)	1,883	-	FS	921	105	0.1	0.5	1.1	176
Solar for School (Solar BC)	22	1	23	120	0	120	13	155	15%	77%	8%	265	100%	265	25	0	-	8	32	N/A	32	4	N/A	3,042	0	-	1.4	13	36	2.8	0.6	0.2	(123)
NGV Vehicles (Abbots)	2,275	1	2,276	0	0	0	0	2,276	100%	0%	0%	(193,275)	100%	(193,275)	8	5,000	-	FS	(11,499)	27,944	(11,235)	(1,740)	1,733	(1,147,424)	31,049	-	FS	12,975	1,733	0.1	0.8	2.0	14,170
Solar Residential Hot Water Pilot Program	50	26	76	40	0	40	165	281	27%	14%	59%	420	100%	420	25	0	2	16	61	N/A	50	7	N/A	4,829	0	26	0.8	165	57	0.3	0.5	0.2	(220)
NGV Vehicles (Waste Management Inc.)	804	1	804	0	0	0	0	804	100%	0%	0%	(21,140)	100%	(21,140)	10	468	-	FS	(1,481)	3,100	(1,456)	(221)	3,100	(147,454)	3,445	-	FS	1,678	3,100	1.8	0.6	1.4	815
Total Commercial	3,926	29	3,955	160	0	160	600	4,715	84%	0	13%	(225,989)		(225,989)		5,771	2	FS	(13,509)	32,739	(13,219)	(2,048)	4,938	(1,350,618)	36,377	26	FS	15,867	4,938	0.3	0.8	1.8	14,515

FORTIS BC

	PROGRAM														
2011 Innovative Technologies Planned	COSTS ($000)											SAVINGS (GJ)			LIFE
FEVI	Utility			Partners											Years
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net	
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2011															
RESIDENTIAL:															
SolarBC Schools Incentive Program	5	0	5	33	0	33	3	41	12%	80%	8%	61	100%	61	25
Total IT	5	0	5	33	0	33	3	41	12%	80%	8%	61	100%	61	25

	ALTERNATE		NET PRESENT VALUE										BENEFIT/COST						
2011 Innovative Technologies Planned	Impact		Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEVI	Energy	Capacity	($/GJ)	Program	Alternate	Program	Carbon Tax	Alternate	Natural Gas	Alternate Energy	Alternate Capacity	Natural Gas	Total Costs	Total Benefits	Benefit/Cost	Natural Gas		TRC Net Benefits
	MWh	kW		($'000s)	($'000s)	($'000s)	($'000s)	($'000s)	(GJ)	(MWh)	(kW)	Utility	($'000s)	($'000s)		Rate Impact	Total Resource	($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																		
RESIDENTIAL:																		
SolarBC Schools Incentive Program	0	-	7	8	N/A	13	1	N/A	716	-	-	1.6	3	14	4.5	0.4	0.2	(33)
Total IT	-	-	7	8	N/A	13	1	N/A	716	-	-	1.6	3	14	4.5	0.4	0.2	(33)

FORTIS BC

	PROGRAM															ALTERNATE	
2011 High Carbon Fuel Switching Programs Planned	COSTS ($000)											SAVINGS (GJ)			LIFE	Impact	
FEI	Utility			Partners											Years	Energy	Capacity
	Incentives	Administration	Total	Incentives	Administration	Total	Participant	Total	% Utility	% Partner	% Participant	Gross	Net-to-Gross	Net		L	kW
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program	Program	Program
Switch 'N' Shrink High Carbon Fuel Switching	100	21	121	-	-	-	-	121	100%	-	0%	(3,440)	50%	(1,720)	18	4	-
Total Residential	100	21	121	-	-	-	-	121		-	0%	(3,440)		(1,720)		4	-

	NET PRESENT VALUE									BENEFIT/COST						
2011 High Carbon Fuel Switching Programs Planned	Levelized Cost	Utility Benefits (Costs)		Participant Benefits (Costs)			Program Net Savings				Participant					
FEI	($/GJ)	Program ($'000s)	Alternate ($'000s)	Program ($'000s)	Carbon Tax ($'000s)	Alternate ($'000s)	Natural Gas (GJ)	Alternate Energy (MWh)	Alternate Capacity (kW)	Natural Gas Utility	Total Costs ($'000s)	Total Benefits ($'000s)	Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
Switch 'N' Shrink High Carbon Fuel Switching	FS	(178)	506	(186)	(25)	506	(17,116)	20	-	FS	211	506	2.4	0.6	1.7	207
Total Residential	FS	(178)	506	(186)	(25)	506	(17,116)	20	-	FS	211	506	2.4	0.6	1.7	207

FORTIS BC

2011 High Carbon Fuel Switching Programs Planned – FEVI	PROGRAM – COSTS ($000) – Utility – Incentives	Utility – Administration	Utility – Total	Partners – Incentives	Partners – Administration	Partners – Total	Participant	Total	% Utility	% Partner	% Participant	SAVINGS (GJ) – Gross	Net-to-Gross	Net	LIFE – Years
Label	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Source Sheet or Calculation	Program	Program	B+C	Program	Program	E+F	Program	D+G+H	D/I	G/I	H/I	Program	Program	MxN	Program
2011															
RESIDENTIAL:															
Switch 'N' Shrink High Carbon Fuel Switching	320	83	403	0	0	0	0	403	100%	0%	0%	(13,760)	50%	(6,880)	18
Total Residential	320	83	403	-	-	-	0	403	100%	-	0%	(13,760)		(6,880)	

2011 High Carbon Fuel Switching Programs Planned – FEVI	ALTERNATE – Impact – Energy (MWh)	Impact – Capacity (kW)	NET PRESENT VALUE – Levelized Cost ($/GJ)	Utility Benefits (Costs) – Program ($'000s)	Utility Benefits (Costs) – Alternate ($'000s)	Participant Benefits (Costs) – Program ($'000s)	Participant Benefits (Costs) – Carbon Tax ($'000s)	Participant Benefits (Costs) – Alternate ($'000s)	Program Net Savings – Natural Gas (GJ)	Program Net Savings – Alternate Energy (MWh)	Program Net Savings – Alternate Capacity (kW)	BENEFIT/COST – Natural Gas Utility	Participant – Total Costs ($'000s)	Participant – Total Benefits ($'000s)	Participant – Benefit/Cost	Natural Gas Rate Impact	Total Resource	TRC Net Benefits ($'000s)
Label	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
Source Sheet or Calculation	Program	Program	D/Y	OxAJ	Q x N x AL	M x N x AN	M x N x AO	N x (QxAP + RxAQ)	PV(AI,P,-O)	PV(AK,P,-Q*N)	PV(AK,P,-R)	T/D	H>0, (V+W)<0	H<0, (V+W)>0, X	AD/AC	T/(V+D)	(T+U)/I	(T+U)-I
2011																		
RESIDENTIAL:																		
Switch 'N' Shrink High Carbon Fuel Switching	15	-	FS	(739)	2,023	(1,067)	(103)	2,023	(69,759)	80	-	FS	1,170	2,023	1.7	0.9	1.8	881
Total Residential	15	-	FS	(739)	2,023	(1,067)	(103)	2,023	(69,759)	80	-	FS	1,170	2,023	1.7	0.9	1.8	881

Appendix C

DSM REGULATION AND BCUC ORDERS

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

Ministerial Order No.

M 271

I, Richard Neufeld, Minister of Energy, Mines and Petroleum Resources, order that the attached regulation is made.

DEPOSITED

NOV 7 2008

B.C. REG. 326/2008

November 6, 2008

Date

Minister of Energy, Mines and Petroleum Resources

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 125.1 (4) (e)

Other (specify):-

November 3, 2008 R/1175/2008/27

DEMAND-SIDE MEASURES REGULATION

Definitions

1 In this regulation:

"Act" means the *Utilities Commission Act*;

"bulk electricity purchaser" means a public utility that purchases electricity from the authority for resale to the public utility's customers;

"community engagement program" means a program delivered by

(a) a public utility to a public entity either

(i) to increase the public entity's awareness about ways to increase energy conservation and energy efficiency or to encourage the public entity to conserve energy or use energy efficiently, or

(ii) to assist the public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently, or

(b) a public utility in cooperation with a public entity to increase the public's awareness about ways to increase energy conservation and energy efficiency or to encourage the public to conserve energy or use energy efficiently;

"education program" means an education program about energy conservation and efficiency, and includes the funding of the development of such a program;

"energy device" has the same meaning as in the *Energy Efficiency Act*;

"energy efficiency training" means training for persons who

(a) manufacture, sell or install energy-efficient products,

(b) design, construct or act as a real estate broker with respect to energy-efficient buildings,

(c) manage energy systems in buildings, or

(d) conduct energy efficiency audits;

"energy-using product" has the same meaning as in the *Energy Efficiency Act* (Canada);

"expenditure portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the Act;

"low-income household" means a household whose residents receive service from the public utility and who have, in a taxation year, a before-tax annual household income equal to or less than the low-income cut off established by Statistics Canada for that year for households of that type;

"plan portfolio" means the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the Act;

"public awareness program" means a program delivered by a public utility

(a) to increase the awareness of the public, including the public utility's customers, about ways to increase energy conservation and energy efficiency or to encourage the public, including the public utility's customers, to conserve energy or use energy efficiently, or

(b) to increase participation by the public utility's customers in other demand-side measures proposed by the public utility in an expenditure portfolio or a plan portfolio

but does not include a program to increase the amount of energy sold or delivered by the public utility;

"public entity" means a local government, first nation, non-profit society incorporated under the *Society Act* or trade union;

"regulated item" means

(a) an energy device,

(b) an energy-using product,

(c) a building design, or

(d) thermal insulation;

"school" means a school regulated under the *School Act* or the *Independent School Act*;

"specified demand-side measure" means

(a) a demand-side measure referred to in section 3 (c) or (d),

(b) the funding of energy efficiency training,

(c) a community engagement program, or

(d) a technology innovation program;

"specified standard" means a standard in any of the following:

(a) the Energy Efficiency Standards Regulation, B.C. Reg. 389/93;

(b) the Energy Efficiency Regulations S.O.R./94-651;

(c) the British Columbia Building Code, if the standard promotes energy conservation or the efficient use of energy;

"technology innovation program" means a program

(a) to develop a technology, a system of technologies, a building design or an industrial facility design that is

(i) not commonly used in British Columbia, and

(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,

(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or

(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a).

Application

2 (1) This regulation applies only with respect to demand-side measures proposed by the authority.

(2) Effective June 1, 2009,

(a) subsection (1) is repealed, and

(b) section 3 does not apply to a public utility that is owned or operated by a local government or has fewer than 10,000 customers.

Adequacy

3 A public utility's plan portfolio is adequate for the purposes of section 44.1 (8) (c) of the Act only if the plan portfolio includes all of the following:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools in the public utility's service area,

(d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

Cost effectiveness

4 (1) Subject to subsections (4) and (5), the commission, in determining for the purposes of section 44.1 (8) (c) or 44.2 (5) (d) of the Act the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of

(a) the demand-side measure individually,

(b) the demand-side measure and other demand-side measures in the portfolio, or

(c) the portfolio as a whole.

(2) In determining whether a demand-side measure referred to in section 3 (a) is cost effective, the commission must,

(a) in addition to conducting any other analysis the commission considers appropriate, use the total resource cost test, and

(b) in using the total resource cost test, consider the benefit of the demand-side measure to be 130% of its value when determined without reference to this subsection.

(3) In determining whether a demand-side measure of a bulk electricity purchaser is cost-effective, the commission must consider the benefit of the avoided supply cost to be the authority's long-term marginal cost of acquiring new electricity to replace the electricity sold to the bulk electricity purchaser and not the bulk electricity purchaser's cost of purchasing electricity from the authority.

(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole.

(5) If the commission is satisfied that a public awareness program proposed in a plan portfolio or an expenditure portfolio is likely to accomplish the goals set out in paragraph (a) or (b) of the definition of "public awareness program", the commission must determine the cost-effectiveness of the program by determining whether the portfolio is cost-effective as a whole.

(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure.

(7) In considering the benefit of a demand-side measure that, in the commission's opinion, will increase the market share of a regulated item with respect to which there is a specified standard that has not yet commenced, the commission may include in the benefit a proportion of the benefit that, in the commission's opinion, will result from the commencement and application of the specified standard with respect to the regulated item.

2010 Legislative Session: 2nd Session, 39th Parliament
FIRST READING

HONOURABLE BLAIR LEKSTROM
MINISTER OF ENERGY, MINES AND PETROLEUM RESOURCES

BILL 17 — 2010
CLEAN ENERGY ACT

Contents

Explanatory Note

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of the Province of British Columbia, enacts as follows:

Definitions

1 (1) In this Act:

"acquire", used in relation to the authority, means to enter into an energy supply contract;

"authority" has the same meaning as in section 1 of the *Hydro and Power Authority Act*;

"British Columbia's energy objectives" means the objectives set out in section 2;

"Burrard Thermal" means the gas-fired generation asset owned by the authority and located in Port Moody, British Columbia;

"clean or renewable resource" means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource;

"demand-side measure" means a rate, measure, action or program undertaken

(a) to conserve energy or promote energy efficiency,

(b) to reduce the energy demand a public utility must serve, or

(c) to shift the use of energy to periods of lower demand,

but does not include

(d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or

(e) any rate, measure, action or program prescribed;

"electricity self-sufficiency" means electricity self-sufficiency as described in section 6 (2);

"expenditure for export" means the amount of an expenditure for the construction or extension of a plant or system or for an acquisition of electricity that is in addition to the amount the authority would have had to spend

(a) to achieve electricity self-sufficiency, and

(b) to undertake anything referred to in section 7 (1), except to the extent the expenditure is accounted for in paragraph (a);

"feed-in tariff program" means a program, that may be established under section 16, under which the authority offers to enter into energy supply contracts with persons generating electricity from clean or renewable resources using prescribed technologies in prescribed regions of British Columbia;

"greenhouse gas" has the same meaning as in section 1 of the *Greenhouse Gas Reduction Targets Act*;

"heritage assets" means

(a) any equipment or facilities for the transmission or distribution of electricity in respect of which, on the date on which this Act receives First Reading in the Legislative Assembly, a certificate of public convenience and necessity has been granted, or has been deemed to have been granted, to the authority or the transmission corporation under the *Utilities Commission Act*,

(b) generation and storage assets identified in Schedule 1 of this Act, and

(c) equipment and facilities that are for the transmission or distribution of electricity and that are identified in Schedule 1 of this Act;

"integrated resource plan" means an integrated resource plan required to be submitted under section 3;

"transmission corporation" means British Columbia Transmission Corporation.

(2) Words and expressions used but not defined in this Act or the regulations, unless the context otherwise requires, have the same meanings as in the *Utilities Commission Act*.

PART 1 — BRITISH COLUMBIA'S ENERGY OBJECTIVES

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract*

Act continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

Integrated resource plans

3 (1) The authority must submit to the minister, in accordance with subsection (6), an integrated resource plan that is consistent with good utility practice and that includes all of the following:

(a) a description of the authority's forecasts, over a defined period, of its energy and capacity requirements to achieve electricity self-sufficiency;

(b) a description of what the authority plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives, including plans respecting

(i) the implementation of demand-side measures,

(ii) the construction or extension of facilities,

(iii) the acquisition of electricity from other persons, and

(iv) the use of rates, including rates to encourage

(A) energy conservation or efficiency,

(B) the use of energy during periods of lower demand,

(C) the reduction of the energy demand the authority must serve, or

(D) the development and use of electricity from clean or renewable resources;

(c) a description of the consultations carried out by the authority respecting the development of the integrated resource plan;

(d) a description of

(i) the expected export demand during a defined period,

(ii) the potential for British Columbia to meet that demand,

(iii) the actions the authority has taken to seek suitable opportunities for the export of electricity from clean or renewable resources, and

(iv) the extent to which the authority has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports;

(e) if the authority plans to make an expenditure for export, a specification of the amount of the expenditure and a rationale for making it.

(2) In the first integrated resource plan the authority submits to the minister, and in any other integrated resource plan the minister by order specifies, the authority must include a description of the authority's infrastructure and capacity needs for electricity transmission for the period ending 30 years after the date the integrated resource plan is submitted.

(3) The description referred to in subsection (2) must include an assessment of the potential for developing, during the period referred to in subsection (2), grouped by geographic area, electricity generation from clean or renewable resources in British Columbia.

(4) The authority must carry out any consultations required by a regulation under section 35 (g) and submit a report to the minister, within the time prescribed, respecting those consultations.

(5) The authority must plan to rely on no energy and no capacity from Burrard Thermal, except in the case of emergency or as authorized by regulation.

(6) An integrated resource plan must be submitted

(a) within 18 months from the date this Part comes into force, and

(b) once every 5 years after the submission under paragraph (a), unless a submission date is prescribed for the purposes of this subsection, in which case an integrated resource plan must be submitted by the prescribed submission date.

(7) The authority may submit an amendment to an integrated resource plan approved under section 4, and section 4 applies to the submission.

(8) If the Lieutenant Governor in Council approves an amendment submitted under subsection (7), the approved amendment is to be considered a part of the approved integrated resource plan.

Approval and procurement

4 (1) After the minister receives an integrated resource plan, the Lieutenant Governor in Council, for the purposes of sections 44.2 (5.1), 46 (3.3) and 71 (2.21) and (2.51) of the *Utilities Commission Act*, may, by order,

(a) approve or reject the plan, and

(b) if the Lieutenant Governor in Council is satisfied that it is in the interests of British Columbians to pursue opportunities for export, require the authority, its subsidiaries or both to do the following:

(i) begin a process or processes by the time specified in the order to acquire the specified amount per year of energy and capacity from clean or renewable resources;

(ii) acquire the energy and capacity referred to in subparagraph (i) within the time specified in the order;

(iii) secure the necessary transmission capacity;

(iv) submit, for the purposes of subsection (2), a report to the minister respecting the expenditures for export resulting from compliance with subparagraphs (i) to (iii).

(2) In an order under subsection (1) (b) of this section, the Lieutenant Governor in Council may exempt the authority from sections 45 to 47 of the *Utilities Commission Act* with respect to anything to be done under subsection (1) (b) (iii) of this section.

(3) The authority and its subsidiaries and persons and their successors and assigns who enter into an energy supply contract as a result of a process referred to in subsection (1) (b) (i) of this section are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(4) The Lieutenant Governor in Council, for the purposes of subsection (5) (a), may approve a report submitted under subsection (1) (b) (iv).

(5) In setting rates for the authority, the commission must ensure that the rates do not allow the authority to recover

(a) its expenditures for export as set out in a report approved by the Lieutenant Governor in Council under subsection (4), and

(b) any other expenditures for export.

Status report

5 (1) The authority must submit to the minister, by the time the minister requires, a status report respecting the authority's most recently approved integrated resource plan.

(2) The minister must make public a status report submitted under subsection (1) in the same manner and at the same time that the minister makes public a service plan under the *Budget Transparency and Accountability Act*.

Electricity self-sufficiency

6 (1) In this section:

"electricity supply obligations" means

(a) electricity supply obligations for which rates are filed with the commission under section 61 of the *Utilities Commission Act*, and

(b) any other electricity supply obligations that exist at the time this section comes into force,

determined by using the authority's prescribed forecasts of its energy requirements and peak load, taking into account demand-side measures, that are in an integrated resource plan approved under section 4;

"heritage energy capability" means the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under prescribed water conditions.

(2) The authority must achieve electricity self-sufficiency by holding,

(a) by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations, and

(b) by the year 2020 and each year after that, the rights to 3 000 gigawatt hours of energy, in addition to the amount of electricity referred to in paragraph (a), and the capacity required to integrate that energy

solely from electricity generating facilities within the Province,

(c) assuming no more in each year than the heritage energy capability, and

(d) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2) (a) and (b), except to the extent the authority may be permitted, by regulation, to enter into contracts in the

prescribed circumstances and on the prescribed terms and conditions.

(4) A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* for

(a) the construction or extension of generation facilities, and

(b) energy purchases,

must consider British Columbia's energy objective to achieve electricity self-sufficiency.

Exempt projects, programs, contracts and expenditures

7 (1) The authority is exempt from sections 45 to 47 and 71 of the *Utilities Commission Act* to the extent applicable, and from any other sections of that Act that the minister may specify by regulation, with respect to the following projects, programs, contracts and expenditures of the authority, as they may be further described by regulation:

(a) the Northwest Transmission Line, a 287 kilovolt transmission line between the Skeena substation and Bob Quinn Lake, and related facilities and contracts;

(b) Mica Units 5 and 6, a project to install two additional turbines and related works and equipment at Mica;

(c) Revelstoke Unit 6, a project to install an additional turbine and related works and equipment at Revelstoke;

(d) Site C, a project to build a third dam on the Peace River in northeast British Columbia to provide approximately

(i) 4 600 gigawatt hours of energy each year, and

(ii) 900 megawatts of capacity;

(e) a bio-energy phase 2 call to acquire up to 1 000 gigawatt hours per year of electricity;

(f) one or more agreements with pulp and paper customers eligible for funding under Canada's Green Transformation Program under which agreement or agreements the authority acquires, in aggregate, up to 1 200 gigawatt hours per year of electricity;

(g) the clean power call request for proposals, issued on June 11, 2008, to acquire up to 5 000 gigawatt hours per year of electricity from clean or renewable resources;

(h) the standing offer program described in section 15;

(i) the feed-in tariff program described in section 16;

(j) the actions taken to comply with section 17 (2) and (3);

(k) the program described in section 17 (4).

(2) The persons and their successors and assigns who enter into an energy supply contract with the authority related to anything referred to in subsection (1) are exempt from section 71 of the *Utilities Commission Act* with respect to the energy supply contract.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent the authority from doing anything referred to in subsection (1).

Rates

8 (1) In setting rates under the *Utilities Commission Act* for the authority, the commission must ensure that the rates allow the authority to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to

(a) the achievement of electricity self-sufficiency, and

(b) a project, program, contract or expenditure referred to in section 7 (1), except

(i) to the extent the expenditure is accounted for in paragraph (a), and

(ii) for costs, prescribed for the purposes of this section, respecting the feed-in tariff program.

(2) Subject to subsection (1) of this section, the commission must set under the *Utilities Commission Act* a rate proposed by the authority with respect to the project referred to in section 7 (1) (a) of this Act.

(3) The commission must not, except on application by the authority, cancel, suspend or amend a rate set in accordance with subsection (2).

(4) The authority must provide to the minister, in accordance with the regulations, an annual report comparing the electricity rates charged by the authority with electricity rates charged by public utilities in other jurisdictions in North America, including an assessment of the extent to which the authority's electricity rates continue to be competitive with those other rates.

Domestic long-term sales contracts

9 The authority must establish, in accordance with the regulations, a program to develop potential offers respecting domestic long-term sales contracts for availability to prescribed classes of customers on prescribed terms, including terms respecting price, for prescribed volumes of energy over prescribed periods.

PART 2 — PROHIBITIONS

Two-rivers system development

10 In this Part:

"approval" includes a certificate, licence, permit or other authorization;

"prohibited projects" means

(a) a project of the authority, referred to in Schedule 2 of this Act, for electricity generation on a stream, and

(b) a project for electricity generation on a stream with a storage capability in excess of a prescribed storage capability,

but does not include the two-rivers projects;

"stream" has the same meaning as in section 1 of the *Water Act*;

"two-rivers projects" means

(a) the authority's facilities, on the Peace River and the Columbia River System, existing on the date this section comes into force and upgrades or extensions to those facilities, and

(b) the project commonly known as Site C.

Project prohibitions

11 (1) Despite any other enactment, a minister, or an employee or agent of the government or of a municipality or regional district, must not issue an approval under an applicable enactment for a person to

(a) undertake a prohibited project, or

(b) construct all or part of the facilities of a prohibited project.

(2) Despite any other enactment, an approval under another enactment is without effect if it is issued contrary to subsection (1).

Prohibited acquisitions

12 (1) In this section:

"facility" means a facility for the generation of electricity and any transmission or distribution equipment to deliver that electricity to the point of interconnection with the authority's integrated service area;

"protected area" means

(a) a park, recreation area, or conservancy, as defined in section (1) of the *Park Act*,

(b) an area established under the *Environment and Land Use Act* as a park or protected area, or

(c) an area established or continued as an ecological reserve under the *Ecological Reserve Act* or by the *Protected Areas of British Columbia Act*.

(2) The authority must not make an offer to acquire electricity from a person whose proposed facility is to be located, in whole or in part, in a protected area, unless the location is permitted under the enactments referred to in the definition of "protected area" in subsection (1).

(3) A person referred to in subsection (2) must not offer to sell electricity to the authority.

Burrard Thermal

13 The authority must not operate Burrard Thermal, except

(a) in the case of emergency,

(b) to provide transmission support services, or

(c) as authorized by regulation.

PART 3 — PRESERVING HERITAGE ASSETS

Sale of heritage assets prohibited

14 (1) The authority must not sell or otherwise dispose of the heritage assets.

(2) Nothing in subsection (1) prevents the authority from disposing of heritage assets if the assets disposed of are no longer used or useful for their intended purpose, or they are to be replaced with one or more assets that will perform similar functions.

PART 4 — STANDING OFFER AND FEED-IN TARIFF PROGRAMS

Standing offer program

15 (1) In this section:

"eligible facility" means a generation facility that

(a) either

(i) has only one generator and the generator's nameplate capacity is less than or equal to the maximum nameplate capacity or has more than one generator and the total nameplate capacity of all of them is a capacity less than or equal to the maximum nameplate capacity, or

(ii) meets the prescribed requirements, and

(b) either

(i) is a high-efficiency cogeneration facility, or

(ii) generates energy by means of a prescribed technology or from clean or renewable resources,

but does not include a prescribed generation facility or class of generation facilities;

"maximum nameplate capacity" means 10 megawatts or, if another capacity is prescribed for the purposes of this section, the prescribed capacity.

(2) The authority must establish and, except in the prescribed circumstances, maintain a standing offer program to acquire electricity from eligible facilities.

(3) The authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions on which offers under the standing offer program under subsection (2) are to be made.

Feed-in tariff program

16 (1) To facilitate the achievement of one or more of British Columbia's energy objectives, the Lieutenant Governor in Council, by regulation, may require the authority to establish a feed-in tariff program.

(2) If the authority is required to establish a feed-in tariff program, the authority may establish, in accordance with the prescribed requirements, if any, the criteria, terms and conditions under which offers may be made under the feed-in tariff program.

(3) The authority may not enter into an energy supply contract as a result of an offer made under the feed-in tariff program if the energy supply contract, by itself or in aggregate with other energy supply contracts entered into under the feed-in tariff program, would result in an expenditure that exceeds the prescribed amount in the prescribed period.

(4) Without limiting section 34 (2) (c),

(a) requirements prescribed by the Lieutenant Governor in Council, and

(b) criteria, terms and conditions established by the authority

made for the purpose of subsection (2) may be made with respect to different regions, prices and technologies.

PART 5 — ENERGY EFFICIENCY MEASURES AND GREENHOUSE GAS REDUCTIONS

Smart meters

17 (1) In this section:

"private dwelling" means

(a) a structure that is occupied as a private residence, or

(b) if only part of a structure is occupied as a private residence, that part of the structure;

"smart grid" means the prescribed equipment;

"smart meter" means a meter that meets the prescribed requirements, and includes related components, equipment and metering and communication infrastructure that meet the prescribed requirements.

(2) Subject to subsection (3), the authority must install and put into operation smart meters and related equipment in accordance with and to the extent required by the regulations.

(3) The authority must complete all obligations imposed under subsection (2) by the end of the 2012 calendar year.

(4) The authority must establish a program to install and put into operation a smart grid in accordance with and to the extent required by the regulations.

(5) The authority may, by itself, or by its engineers, surveyors, agents, contractors, subcontractors or employees, enter on any land, other than a private dwelling, without the consent of the owner, for a purpose relating to the use, maintenance, safeguarding, installation, replacement, repair, inspection, calibration or reading of its meters, including smart meters, or of its smart grid.

(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters, other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

Greenhouse gas reduction

18 (1) In this section, **"prescribed undertaking"** means a project, program, contract or expenditure that is in a class of projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia.

(2) In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking.

(3) The commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

(4) A public utility referred to in subsection (2) must submit to the minister, on the minister's request, a report respecting the prescribed undertaking.

(5) A report to be submitted under subsection (4) must include the information the minister specifies and be submitted in the form and by the time the minister specifies.

Clean or renewable resources

19 (1) To facilitate the achievement of British Columbia's energy objective set out in section 2 (c), a person to whom this subsection applies

(a) must pursue actions to meet the prescribed targets in relation to clean or renewable resources, and

(b) must use the prescribed guidelines in planning for

(i) the construction or extension of generation facilities, and

(ii) energy purchases.

(2) Subsection (1) applies to

(a) the authority, and

(b) a prescribed public utility, if any, and a public utility in a class of prescribed public utilities, if any.

PART 6 — FIRST NATIONS CLEAN ENERGY BUSINESS FUND

First Nations Clean Energy Business Fund

20 (1) In this section:

"first nation" means

(a) a band, as defined in the *Indian Act* (Canada), and

(b) an aboriginal governing body, however organized and established by aboriginal people;

"power project" means an electricity generation or transmission project

(a) that is in a class of projects prescribed for the purposes of this section, other than a project of any organization in the government reporting entity, as defined in the *Budget Transparency and Accountability Act*,

(b) for which a licence, if applicable, under the *Water Act* for a power purpose, as defined section 1 of that Act, is issued after the date this section comes into force, and

(c) for which a prescribed authorization, if applicable, under an enactment respecting land is granted after this section comes into force;

"special account" means the special account, as defined in section 1 of the *Financial Administration Act*, established under subsection (2) of this section.

(2) A special account, to be known as the First Nations Clean Energy Business Fund special account, is established.

(3) The initial balance of the special account is an amount, not to exceed $5 million, prescribed by Treasury Board.

(4) The balance of the special account is increased by

(a) any other amount received by the government for payment into the account, and

(b) a prescribed percentage of the prescribed land and water revenues the government derives from power projects.

(5) Despite section 21 (3) of the *Financial Administration Act*, the minister, in accordance with a spending plan approved by Treasury Board, may pay an amount of money out of the special account for any of the following purposes:

(a) to share the revenues referred to in subsection (4) (b), up to a prescribed percentage of the revenue, under an agreement or agreements with one or more first nations;

(b) to facilitate the participation of first nations and aboriginal people in the clean energy sector;

(c) to pay the costs of administering the special account.

PART 7 — TRANSMISSION CORPORATION

Division 1 — Transfer of Property, Shares and Obligations

Definitions

21 In this Division:

"excluded contract" means a contract that was entered into, assumed by or assigned to the transmission corporation and that is governed by the law of a jurisdiction other than British Columbia;

"excluded permit" means a permit, approval, registration, authorization, licence, exemption, order or certificate issued, granted or provided to the transmission corporation under the law of a jurisdiction other than British Columbia;

"included contract" includes any contract entered into, assumed by or assigned to the transmission corporation, but does not include an excluded contract;

"included permit" includes a permit, approval, registration, authorization, licence, exemption, order or certificate, including a certificate of public convenience and necessity under the *Utilities Commission Act*, but does not include an excluded permit;

"right", in relation to a right held by the authority or the transmission corporation, includes a right under a trust, a cause of action and a claim.

Transfer of property

22 (1) Subject to subsection (2) and despite any enactment or law to the contrary, on the coming into force of this Part, all of the transmission corporation's rights, property, assets, included contracts and included permits are transferred to and vested in the authority.

(2) Subsection (1) does not apply to excluded contracts and excluded permits.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, the shares of the transmission corporation are transferred to and vested in the authority.

(4) The shares transferred to and vested in the authority under subsection (3) must not be sold or otherwise disposed of, but may be surrendered for cancellation.

(5) Despite any enactment or law to the contrary,

(a) the transfer and vesting effected by subsections (1) and (3) take effect without

(i) the execution or issue of any record, or

(ii) any registration or filing of this Act or any other record in or with any registry or other office,

(b) the transfer and vesting effected by subsections (1) and (3) take effect despite

(i) any prohibition on all or any part of the transfer and vesting, and

(ii) the absence of any consent or approval that is or may be required for all or any part of the transfer and vesting,

(c) if any right, property, asset, included contract or included permit referred to in subsection (1) is registered or otherwise recorded in the name of the transmission corporation, the registration or record may remain but is deemed, for all purposes of this and all other enactments and law, to reflect that the right, property, asset, included contract or included permit is owned by and vested in or held by the authority, and

(d) in any record in or by which the authority deals with a right, property, asset, included contract or included permit referred to in subsection (1), it is sufficient to cite this Act as effecting and confirming the transfer from the transmission corporation to the authority of the included contract or included permit or of the title to the right, property or asset and the vesting of that title in the authority.

(6) For the purposes of this section, assets that become assets of the authority under this section include records and parts of records, and, without limiting this, all of the records and parts of records of the transmission corporation are transferred to and become the records of the authority on the coming into force of this Part.

(7) Without limiting subsection (5) (c) of this section, or section 383.1 of the *Land Title Act*, if a right, property or asset referred to in subsection (1) of this section is registered or recorded in the name of the transmission corporation,

(a) the authority may, in its own name,

(i) effect a transfer, charge, encumbrance or other dealing with the right, property or asset, and

(ii) execute any record required to give effect to that transfer, charge, encumbrance or other dealing, and

(b) an official

(i) who has authority over a registry or office, including, without limitation, the personal property registry and a land title office, in which title to or interests in the right, property or asset is registered or recorded, and

(ii) to whom a record referred to in paragraph (a) (ii) executed by or on behalf of the authority is submitted in support of the transfer, charge, encumbrance or other dealing

must give the record the same effect as if it had been duly executed by the transmission corporation.

Transfer of obligations and liabilities

23 On the coming into force of this Part, all obligations and liabilities of the transmission corporation, except for obligations and liabilities under an excluded contract or excluded permit,

(a) are transferred to and assumed by the authority,

(b) become the authority's obligations and liabilities,

(c) cease to be obligations and liabilities of the transmission corporation, and

(d) may be enforced against the authority as if the authority had incurred them.

Records of transferred assets and liabilities

24 (1) Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

(2) If, under this Part, a part of a right, property, asset, obligation or liability is transferred to the authority, any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be amended to reflect the authority's interests in that right, property, asset, obligation or liability.

Transfer is not a default

25 Despite any provision to the contrary in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate, the transfer to the authority of a right, property, asset, included contract, included permit, share, obligation or liability under sections 22 and 23 does not constitute a breach or contravention of, or an event of default under, or confer a right to terminate the document, and, without limiting this, does not entitle any person who has an interest in the right, property, asset, included contract, included permit, share, obligation or liability to claim any damages, compensation or other remedy.

Legal proceedings

26 (1) Any legal proceeding being prosecuted or pending by or against the transmission corporation on the date this Part comes into force may be prosecuted, or its prosecution may be continued, by or against the authority, and may not be prosecuted or continued against the transmission corporation.

(2) A conviction against the transmission corporation may be enforced against the authority, and may not be enforced against the transmission corporation.

(3) A ruling, order or judgment in favour of or against the transmission corporation may be enforced by or against the authority, and may not be enforced by or against the transmission corporation.

(4) A cause of action or claim against the transmission corporation existing on the date this Part comes into force must be prosecuted against the authority.

(5) Subject to subsections (1) to (4), a cause of action, claim or liability to prosecution existing on the date this Part comes into force is unaffected by anything done under this Part.

Division 2 — Employees

Definitions

27 In this Division:

"adjustment plan" means an adjustment plan under section 54 of the *Labour Relations Code*;

"collective agreement" has the same meaning as in section 1 (1) of the *Labour Relations Code*.

Transfer of employees

28 (1) It is deemed that the persons who were, immediately before the coming into force of this Part, employees of the transmission corporation are, on the coming into force of this Part, transferred to and become employees of the authority.

(2) A question or difference between the authority and

(a) a transferred employee who is a member of a unit of employees for which a trade union has been certified under the *Labour Relations Code*, or

(b) a trade union representing transferred employees,

respecting the application of the *Labour Relations Code*, or the interpretation or application of this Division, may be referred to the Labour Relations Board in accordance with the procedure set out in the *Labour Relations Code* and its regulations.

(3) The Labour Relations Board may decide a question or difference referred to in subsection (2) in any of the ways, and by applying any of the remedies, available under the *Labour Relations Code*.

(4) On the date this Part comes into force, in respect of employees who are members of units of employees for which a trade union has been certified under the *Labour Relations Code*, the authority is the successor employer of those employees for the purposes of section 35 of the *Labour Relations Code*, without prejudice to the authority's right to apply for consolidation or merger of the bargaining units.

(5) If the authority or any trade union representing transferred employees makes an application to the Labour Relations Board to consolidate or merge the bargaining units representing transferred employees into a single bargaining unit for each trade union, the Labour Relations Board must consider that application having regard to the principles of business efficiency and without reference to the labour relations history at the authority or the transmission corporation relating to the presence of more than one bargaining unit for each trade union.

Continuous employment

29 (1) The transfer of a transferred employee does not constitute a termination of the transferred employee's employment for the purposes of

(a) an applicable collective agreement,

(b) any employment contract involving the transferred employee, and

(c) the *Employment Standards Act*.

(2) A transferred employee who is not subject to a collective agreement is deemed to have been employed by the authority without interruption in service.

(3) The service, with the transmission corporation, of a transferred employee who is not subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any employment contract.

(4) For the purposes of seniority, a transferred employee who is subject to a collective agreement is deemed to have been employed by the authority without interruption in service, unless the authority and the trade union representing the transferred employee have agreed to other seniority terms in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting seniority in the adjustment plan apply.

(5) The service, with the transmission corporation, of a transferred employee who is subject to a collective agreement is deemed to be service with the authority for the purpose of determining probationary periods and benefits, and any other employment related entitlements, under

(a) the *Employment Standards Act*,

(b) any other enactment, and

(c) any collective agreement,

unless the authority and the trade union representing the transferred employee have agreed to other probationary periods, benefits and entitlements in an adjustment plan within 60 days after notice under section 54 of the *Labour Relations Code* is given, in which case the applicable terms respecting probationary periods, benefits and entitlements in the adjustment plan apply.

(6) A transferred employee is deemed not to have been constructively dismissed solely by virtue of the transfer under section 28.

(7) Nothing in this Part

(a) prevents the employment of a transferred employee from being lawfully terminated after the transfer under section 28,

(b) prevents any term or condition of the employment of a transferred employee from being lawfully changed after the transfer under section 28, or

(c) removes any right or remedy of a person who is terminated after the transfer under section 28 or in respect of whom a term or condition of employment has been changed after the transfer under section 28.

Pensions

30 (1) For the purposes of the *Pension Benefits Standards Act*, the transfer of a transferred employee does not constitute a termination of membership in the transmission corporation's registered pension plan, or any other pension arrangement sponsored by the transmission corporation.

(2) Despite section 36 (1) of the *Hydro and Power Authority Act*, the authority does not require the approval of the Lieutenant Governor in Council to amend the authority's registered pension plan to implement the provisions of this Part, including the authority's assumption of all liability for the pension benefits payable under the transmission corporation's registered pension plan.

(3) Despite any enactment or law to the contrary, on the coming into force of this Part, all of the rights, property and assets that comprise

(a) the balance of fund account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the balance of fund account of the pension fund of the authority's registered pension plan, and

(b) the index reserve account and past service index reserve account of the pension fund of the transmission corporation's registered pension plan are transferred to and vested in the index reserve account of the pension fund of the authority's registered pension plan,

and the resulting pension fund must be held by the trustee of the pension fund of the authority's registered pension plan.

(4) Section 22 (5) applies to the transfer and vesting effected by subsection (3) of this section.

Division 3 — General

Commission subject to direction

31 (1) The minister, by regulation, may issue a direction to the commission with respect to the exercise of powers and the performance of duties of the commission regarding any matter relating to a transfer made under this Part or to the service or rates referred to in section 32.

(2) The commission must comply with a direction issued under subsection (1) despite

(a) any provision of, or regulation under, the *Utilities Commission Act*, except any direction issued under section 3 of that Act, and

(b) any previous decision of the commission.

(3) This section is repealed on July 1, 2011.

Utilities Commission Act

32 (1) No approval, authorization, permit, certificate, exemption, permission, registration or order is required under the *Utilities Commission Act* with respect to

(a) the transmission corporation's ceasing to provide the service referred to in subsection (2) (a), or

(b) any transfer under this Part.

(2) The authority is deemed to have all the approvals, authorizations, permits, certificates, exemptions, permissions, registrations or orders that, under the *Utilities Commission Act*, are or may be required to continue

(a) to provide the service the transmission corporation provided immediately before the coming into force of this Part, and

(b) to charge, collect and enforce the rates the transmission corporation charged, collected and enforced immediately before the coming into force of this Part.

(3) The commission must not, except on application by the authority, cancel, suspend or amend

(a) any approval, authorization, permit, exemption, permission, registration, order or certificate, except for the certificate issued by commission Order C-4-

08, that, under the *Utilities Commission Act*, the authority requires to provide the service and to charge, collect and enforce the rates referred to in subsection (2), or

(b) the service or rates referred to in subsection (2).

(4) Subsection (3) is repealed on July 1, 2011.

Designated agreements

33 On the coming into force of this Part, the agreements designated under section 3 of the *Transmission Corporation Act* have no force or effect.

Part 8 — Regulations

Division 1 — Regulations by Lieutenant Governor in Council

General

34 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the *Interpretation Act*.

(2) In making a regulation under this Act, the Lieutenant Governor in Council may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

Regulations

35 Without limiting section 34 (1), the Lieutenant Governor in Council may make regulations as follows:

(a) respecting forecasts for the purposes of the definition of "electricity supply obligations" in section 6 (1);

(b) adding a heritage asset to Schedule 1 of this Act;

(c) prescribing water conditions for the purposes of the definition of "heritage energy capability" in section 6 (1);

(d) modifying or adding to British Columbia's energy objectives, except for the objective specified in section 2 (g);

(e) for the purposes of sections 44.1, 44.2, 46 and 71 of the *Utilities Commission Act*, respecting the application of British Columbia's energy objectives to public utilities other than the authority;

(f) establishing factors or guidelines the commission must follow in respect of British Columbia's energy objectives, including guidelines regarding the relative priority of the objectives set out in section 2;

(g) respecting consultations the authority must carry out in relation to

(i) the development of an integrated resource plan and of an amendment to an integrated resource plan,

(ii) an integrated resource plan submitted under section 3 (6), and

(iii) an amendment to an integrated resource plan submitted under section 3 (7);

(h) prescribing submission dates for the purposes of section 3 (6);

(i) respecting the authority's obligation under section 6 (3), including, without limitation, regulations permitting the authority to enter into contracts respecting the electricity referred to in section 6 (2) (a) and (b) and prescribing the terms and conditions on which, and the volume of electricity about which, the contracts may be entered into;

(j) respecting the program referred to in section 9, including prescribing classes of customers and terms;

(k) prescribing storage capability for the purposes of the definition of "prohibited projects" in section 10, including, without limitation, prescribing storage capability in terms of time, impoundment, mechanism or area;

(l) respecting the standing offer program to be established under section 15, including, without limitation, regulations that

(i) prescribe requirements, technologies, generation facilities and classes of generation facilities for the purposes of the definition of "eligible facility" in section 15 (1),

(ii) prescribe a capacity for the purposes of the definition of "maximum nameplate capacity" in section 15 (1),

(iii) prescribe circumstances for the purposes of section 15 (2), and

(iv) prescribe requirements for the purposes of section 15 (3);

(m) respecting the feed-in tariff program that may be established under section 16, including, without limitation, regulations that

(i) prescribe regions and technologies for the purposes of the definition of "feed-in tariff program" in section 1 (1),

(ii) require the authority to establish the feed-in tariff program,

(iii) prescribe requirements for the purposes of section 16 (2),

(iv) prescribe amounts and periods for the purposes of section 16 (3), and

(v) prescribe costs for the purposes of section 8 (1) (b);

(n) for the purposes of the definition of "prescribed undertaking" in section 18, prescribing classes of projects, programs, contracts or expenditures that encourage

(i) the use of

(A) electricity, or

(B) energy directly from a clean or renewable resource

instead of the use of other energy sources that produce higher greenhouse gas emissions, or

(ii) the use of natural gas, hydrogen or electricity in vehicles, and the construction and operation of infrastructure for natural gas or hydrogen fueling or electricity charging.

Division 2 — Regulations by Minister

General

36 (1) In making a regulation under this Act, the minister may do one or more of the following:

(a) delegate a matter to a person;

(b) confer a discretion on a person;

(c) make different regulations for different persons, places, things, decisions, transactions or activities.

(2) The minister may make a regulation defining, for the purposes of this Act, a word or expression used but not defined in this Act.

Regulations

37 The minister may make regulations as follows:

(a) prescribing resources for the purposes of the definition of "clean or renewable resource" in section 1 (1);

(b) prescribing exclusions for the purposes of the definition of "demand-side measure" in section 1 (1);

(c) authorizing the authority for the purposes of sections 3 (5), 6 and 13;

(d) describing the projects, programs, contracts and expenditures referred to in section 7 (1), including, without limitation, by specifying the property, interests, rights, activities, contracts and rates that comprise the projects, programs, contracts and expenditures;

(e) specifying sections of the *Utilities Commission Act* for the purposes of section 7 (1);

(f) respecting reports to be provided to the minister by the authority under section 8 (4), including, without limitation, regulations respecting the jurisdictions with which comparisons are to be made, the rate classes to be considered, the factors to be used in making the comparisons and conducting the assessments, and the meaning to be given to the word "competitive";

(g) for the purposes of section 17, respecting smart meters and smart-grids and their installation, including, without limitation,

(i) prescribing the types of smart meters to be installed, including the features or functions each meter must have or be able to perform,

(ii) prescribing types of smart grids to be installed, including, without limitation, equipment to detect unauthorized use or consumption of electricity, equipment to facilitate distributed generation and associated telecommunication and back-up systems, and

(iii) prescribing the classes of users for whom smart meters must be installed, and, without limiting section 36 (1) (c), requiring the authority to install different types of smart meters for different classes of users;

(h) prescribing targets, guidelines, public utilities and classes of public utilities for the purposes of section 19;

(i) issuing a direction for the purposes of section 31.

Division 3 — Regulations by Treasury Board

Regulations

38 Treasury Board may make regulations as follows:

(a) prescribing classes of projects and authorizations for the purposes of the definition of "power project" in section 20 (1), including, without limitation, prescribing classes of projects by reference to whether, or the extent to which, a project is a project of any organization of the government reporting entity, within the meaning of that definition;

(b) prescribing amounts and percentages for the purposes of section 20 (3), (4) (b) and (5) (a).

PART 9 — TRANSITION

Transition

39 (1) The Lieutenant Governor in Council may make regulations considered appropriate for the purpose of more effectively bringing this Act into operation, and to remedy any transitional difficulties encountered in doing so, and for that purpose, may make regulations disapplying or varying any provision of this Act.

(2) Subject to subsection (3), this section is repealed on the date that is 2 years after the coming into force of this section and, on this section's repeal, any regulations made under it are also repealed.

(3) The Lieutenant Governor in Council, by regulation, may substitute for the date referred to in subsection (2) a date that is no later than 3 years after the coming into force of this section.

PART 10 — CONSEQUENTIAL AMENDMENTS

BC Hydro Public Power Legacy and Heritage Contract Act

40 Section 1 of the BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, is amended by repealing the definition of* "protected assets"*.

41 Section 2 is repealed.

42 Section 4 (2) (a) is amended by striking out ", the *Hydro and Power Authority Act* and the *Transmission Corporation Act*;***" and substituting "***and the *Hydro and Power Authority Act*;***".***

43 The Schedule is repealed.

Environmental Assessment Act

44 Section 11 (2) (b) of the Environmental Assessment Act, S.B.C. 2002, c. 43, is amended by adding ", including potential cumulative environmental effects***" after "***assessment***".***

Financial Information Act

45 Schedule 1 of the Financial Information Act, R.S.B.C. 1996, c. 140, is amended by striking out "*Transmission Corporation Act****".***

Forest Act

46 Section 47.6 (2.11) (b) of the Forest Act, R.S.B.C. 1996, c. 157, as enacted by section 18 (c) of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, S.B.C. 2008, c. 20, is amended by striking out everything after "has received notification***" and substituting "***under section 79.1.***"***

47 Section 47.7 (f) (ii) is amended by adding "other than a forestry licence to cut issued under section 47.6 (2.11)***" after "***forestry licence to cut***".***

48 Section 47.72, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended

(a) in subsection (1) (f) by striking out "a regulation made under section 151.6 (2).***" and substituting "***section 79.1.***", and***

(b) in subsection (2) by striking out "of harvest completion***" and substituting "***in accordance with section 79.1***" and by striking out "***a regulation made under section 151.6 (2)***" and substituting "***section 79.1.***"***

49 Section 47.73, as enacted by section 20 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out everything after "gave the notification***" and substituting "***in accordance with section 79.1.***"***

50 Section 47.9, as enacted by section 22 of the Greenhouse Gas Reduction (Emissions Standards) Statutes Amendment Act, 2008, is amended by striking out "a regulation made under section 151.6 (2)***" and substituting "***section 79.1***".***

51 The following Division is added after section 79:

Division 4.1 — Miscellaneous

Order respecting notice

79.1 (1) During the term of an agreement under section 12, the minister may order that the agreement holder must notify the minister, in accordance with the requirements specified in the order, whether the agreement holder has abandoned or intends to abandon any rights the agreement holder has in respect of Crown timber that has been cut under the agreement but has not been removed from an area specified in the order.

(2) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has abandoned or intends to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy or otherwise deal with the Crown timber referred to in that subsection.

(3) If an agreement holder referred to in subsection (1) notifies the minister that the agreement holder has not abandoned and does not intend to abandon the rights referred to in subsection (1), the minister may order the agreement holder not to destroy the Crown timber referred to in that subsection, if the minister is satisfied that a market exists for that Crown timber.

(4) A person to whom an order under this section has been given must comply with the order.

Freedom of Information and Protection of Privacy Act

52 Schedule 2 of the Freedom of Information and Protection of Privacy Act, R.S.B.C. 1996, c. 165, is amended by striking out the following:

Public Body:	British Columbia Transmission Corporation
Head:	Chair ***.***

Hydro and Power Authority Act

53 Section 1 of the Hydro and Power Authority Act, R.S.B.C. 1996, c. 212, is amended in the definition of "power" by adding ", except in sections 12 (1) and 38 (2),***" before "***includes energy***".***

54 Section 12 (1) is repealed and the following substituted:

(1) Subject to this Act and the regulations, the authority has the capacity and the rights, powers and privileges of an individual of full capacity and, in addition, has

(a) the power to amalgamate in any manner with a firm or person, and

(b) any other power prescribed.

(1.1) The authority's purposes are

(a) to generate, manufacture, conserve, supply, acquire and dispose of power and related products,

(b) to supply and acquire services related to anything in paragraph (a), and

(c) to do other things as may be prescribed.

(1.2) The authority may not engage in activities or classes of activities prescribed for the purposes of this subsection without obtaining an applicable approval as prescribed.

55 Section 32 is amended

(a) in subsection (7) (c) by adding "section 32 and***" before "***Division***",***

(b) in subsection (7) by adding the following paragraph:

(c.01) the *Clean Energy Act*; ***,***

(c) in subsection (7) (x) by adding "44.1,***" after "***sections***", and***

(d) by repealing subsection (8).

56 Section 38 is amended by renumbering the section as section 38 (1) and by adding the following subsection:

(2) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations

(a) prescribing powers for the purposes of section 12 (1),

(b) prescribing purposes of the authority for the purposes of section 12 (1.1), and

(c) for the purposes of section 12 (1.2), prescribing activities, classes of activities and approval requirements.

Transmission Corporation Act

57 The Transmission Corporation Act, S.B.C. 2003, c. 44, is repealed.

Utilities Commission Act

58 Section 1 of the Utilities Commission Act, R.S.B.C. 1996, c. 473, is amended by repealing the definitions of* "demand-side measure" *and* "government's energy objectives" *and substituting the following:

"British Columbia's energy objectives" has the same meaning as in section 1 (1) of the *Clean Energy Act*;

"demand-side measure" has the same meaning as in section 1 (1) of the *Clean Energy Act*; ***.***

59 Section 1 is amended by repealing the definition of* "transmission corporation"*.

60 Section 3 (2) is amended by striking out "*or*" at the end of paragraph (a) and by adding the following paragraph:

(a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or ***.***

61 Section 5 (0.1) and (4) to (9) is repealed.

62 Section 28 is amended

(a) in subsection (1) by striking out "*90*" and substituting "*200*", and

(b) by adding the following subsections:

(2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).

(2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite

(a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or

(b) any previous decision of the commission.

63 Section 29 is amended by striking out "90***" and substituting "***200***".***

64 Section 43 (1.1) is repealed.

65 Section 44.1 is amended

(a) by repealing subsections (1) and (4), and

(b) by repealing subsection (8) (a) and (b) and substituting the following:

(a) the applicable of British Columbia's energy objectives,

(b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***.***

66 Section 44.2 is amended

(a) in subsection (3) by striking out "subject to subsections (5) and (6),***" and substituting "***subject to subsections (5), (5.1) and (6),***",***

(b) in subsection (5) by adding "filed by a public utility other than the authority***" after "***expenditure schedule***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, , and

(c) by adding the following subsection:

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

67 Section 46 is amended

(a) in subsection (3) by striking out "Subject to subsections (3.1) and (3.2),***" and substituting "***Subject to subsections (3.1) to (3.3),***",***

(b) in subsection (3.1) by adding "applied for by a public utility other than the authority***" after "***under subsection (3)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***, and***

(c) by adding the following subsection:

(3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.

68 Section 58.1 (2) (a) (ii) is amended by striking out "or 125.1 (4) (f)***".***

69 Part 3.1 is repealed.

70 Section 71 is amended

(a) in subsection (2.1) by adding "filed by a public utility other than the authority***" after "***whether an energy supply contract***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, ***,***

(b) by adding the following subsection:

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,

(d) the quantity of the energy to be supplied under the contract,

(e) the availability of supplies of the energy referred to in paragraph (d),

(f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and

(g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d). ***,***

(c) in subsection (2.5) by adding "with respect to a submission by a public utility other than the authority***" after "***under subsection (2.4)***" and by repealing paragraphs (a) and (c) and substituting the following:***

(a) the applicable of British Columbia's energy objectives,

(c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and ***, and***

(d) by adding the following subsection:

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*, and

(c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

71 Section 125 (2) is amended by adding the following paragraph:

(e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.

72 Section 125.1 is amended

(a) by repealing subsections (2), (3) and (4) (a), (c), (d), (f) and (j) to (n), and

(b) in subsection (4) (e) by adding "and***" at the end of subparagraph (ii), by striking out*** ", and***" at the end of subparagraph (iii) and by repealing subparagraph (iv).***

73 Section 125.2 (3) is amended by striking out "transmission corporation***" and substituting "***authority***".***

Wildfire Act

74 Section 7 of the Wildfire Act, S.B.C. 2004, c. 31, is amended

(a) by adding the following subsections:

(2.1) A person who is in a prescribed class of persons and who carries out an industrial activity or a prescribed activity on an area must, within the prescribed period and to the prescribed extent, abate a fire hazard on the area.

(2.2) A person referred to in subsection (2) is not required to abate a fire hazard on an area if a person referred to in subsection (2.1) is required to abate the fire hazard. ***, and***

(b) in subsection (3) by striking out "subsection (2)***" in both places and substituting "***subsections (2) and (2.1)***" and by adding "***applicable***" before "***person***".***

75 Section 43 (3) is amended by striking out "section 7 (2) or (4),***" and substituting "***section 7 (2), (2.1) or (4),***".***

76 Section 72 (2) (g) is repealed and the following substituted:

(g) respecting the abatement of fire hazards, including, without limitation,

(i) prescribing classes of person, activities and time periods for the purposes of section 7 (2.1), and

(ii) specifying, for the purposes of section 7 (2.1), the extent to which a fire hazard must be abated, .

Commencement

77 The provisions of this Act referred to in column 1 of the following table come into force as set out in column 2 of the table:

Item	Column 1 **Provisions of Act**	Column 2 **Commencement**
1	Anything not elsewhere covered by this table	The date of Royal Assent
2	Section 20	July 5, 2010
3	Section 42	July 5, 2010
4	Section 45	By regulation of the Lieutenant Governor in Council
5	Section 52	By regulation of the Lieutenant Governor in Council
6	Section 55 (d)	July 5, 2010
7	Section 57	July 5, 2010
8	Section 59	July 5, 2010

9	Section 73	July 5, 2010

Schedule 1

Heritage Assets

Those generation and storage assets commonly known as the following:

Aberfeldie

Alouette

Ash River

Bridge River

Buntzen/Coquitlam

Burrard Thermal

Cheakamus

Clowhom

Duncan

Elko

Falls River

Fort Nelson

G. M. Shrum

Hugh Keenleyside Dam (Arrow Reservoir)

John Hart

Jordan

Kootenay Canal

La Joie

Ladore

Mica, including units 1 to 6

Peace Canyon

Prince Rupert

Puntledge

Revelstoke, including units 1 to 6

Ruskin

Site C

Seton

Seven Mile

Shuswap

Spillimacheen

Stave Falls

Strathcona

Waneta

Wahleach

Walter Hardman

Whatshan

Schedule 2

Prohibited Projects

The projects of the authority, as set out in appendix F-8 of the authority's long-term acquisition plan, exhibit B-1-1, filed with the commission on June 12, 2008, are prohibited projects for the purposes of section 10, in particular, the following projects identified in appendix F-8:

(a) Murphy Creek;

(b) Border;

(c) High Site E;

(d) Low Site E;

(e) Elaho;

(f) McGregor Lower Canyon;

(g) Homathko River;

(h) Liard River;

(i) Iskut River;

(j) Cutoff Mountain;

(k) McGregor River Diversion.

Explanatory Note

This Bill sets out British Columbia's energy objectives, requires the British Columbia Hydro and Power Authority to submit an integrated resource plan describing what it plans to do in response to those objectives, and requires the authority to achieve electricity self-sufficiency by the year 2016. The Bill also prohibits certain projects from proceeding, ensures that the benefits of the heritage assets are preserved for British Columbians, provides for the establishment of energy efficiency measures and establishes the First Nations Clean Energy Business Fund. The Transmission Corporation and the authority are also to be unified under this Bill.

IN THE MATTER OF

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.

AND

ENERGY EFFICIENCY AND CONSERVATION APPLICATION

DECISION

April 16, 2009

Before:

A.W.K. Anderson, Commissioner
A.A. Rhodes, Commissioner

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1.0 BACKGROUND AND REGULATORY PROCESS

1.1 The Application

On May 28, 2008 Terasen Gas Inc. (“TGI”) and Terasen Gas (Vancouver Island) Inc. (“TGVI”) (collectively “Terasen”) filed its Energy Efficiency and Conservation (“EEC”) Programs Application (“Application”) with the British Columbia Utilities Commission (“the Commission”).

In the Application, Terasen requested an order or orders approving the following:

- Increases of EEC expenditures in the period 2008-2010 to $46.944 million for TGI and $9.667 million for TGVI, a combined total of $56.6 million;
- Capitalisation of incremental EEC expenditures as a regulatory asset deferral account on an after tax basis and amortisation of the account over 20 years;
- An increase in the amortisation period to 20 years for incentive amounts that are added to deferral accounts for 2008 and 2009 as part of the 2008-2009 extension of the 2004-2007 TGI PBR Settlement Agreement (“TGI PBR Extended Settlement”) approved by Order G-33-07 and the 2008-2009 extension of the 2006-2007 TGVI Revenue Requirements Settlement Agreement (“TGVI RR Extended Settlement”) approved by Order G-34-07;
- Changes to the benefit-cost analysis undertaken to evaluate EEC measures as outlined below:
    - Implementation of a portfolio approach to benefit-cost analysis such that the Total Resource Cost (“TRC”) test for all programs combined must return an overall combined result of one or more;
    - Elimination of the requirement to include free-riders in benefit-cost tests;
    - Inclusion of the benefits of savings associated with implementation of a regulation as a result of EEC programs aimed at preparing the marketplace for the introduction of regulation of minimum efficiency levels in equipment, buildings or energy systems
    - Inclusion of the impact of carbon-pricing as one of the inputs to the benefit-cost tests;

- A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI.

The Commission directed that the Application would follow a written hearing process after hearing submissions from intervenors and interested parties.

Intervenors registered for the hearing were:

- British Columbia Hydro and Power Authority ("BC Hydro"),
- British Columbia Old Age Pensioners' Organization et. al. ("BCOAPO"),
- B.C. Sustainable Energy Association and the Sierra Club of Canada (British Columbia Chapter) (collectively, "BCSEA-SCBC"),
- The Ministry of Energy, Mines and Petroleum Resources ("MEMPR"),
- The Rental Owners and Managers Society of B.C. ("ROMS"),
- FortisBC Inc.,
- Pacific Northern Gas Ltd. ("PNG"),
- The Commercial Energy Consumers Association of BC ("CEC") and
- Direct Energy Marketing Limited

In addition to parties registering as intervenors, numerous letters of comment were received.

Two rounds of Information Requests were conducted.

Intervenors BC Hydro and BCSEA-SCBC also filed evidence.

The process was complete on December 5, 2008 with the filing of Terasen's reply submission.

1.2 Legal and Regulatory

1.2.1 The Utilities Commission Act

The Application is made pursuant to Section 44.2 of the Act, which states, in part:

> "(1) A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> > (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;…"

and:

> "(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5) and (6), must
>
> > (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
> >
> > (b) reject the schedule.
>
> (4) The commission may accept or reject, under subsection (3), a part of a schedule.
>
> (5) In considering whether to accept an expenditure schedule, the commission must consider
>
> > (a) the government's energy objectives,
> >
> > (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
> >
> > (c) whether the schedule is consistent with the requirements under section 64.01 or 64.02, if applicable,
> >
> > (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
> >
> > (e) the interests of persons in British Columbia who receive or may receive service from the public utility.
>
> (6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.”

1.2.2 The Long Term Resource Plan

The Commission Panel notes that, with respect to subsection 44.2 (5) (b) and subsection 44.2(6), Terasen filed its consolidated 2008 Resource Plan (on behalf of TGI, TGVI and Terasen Gas (Whistler) Inc.) on June 27, 2008, which was accepted as described in Order G-194-08 and its accompanying Reasons. As noted in the Reasons, the Commission Panel specifically excluded any consideration or determination with respect to whether the EEC expenditures included in the instant Application were in the public interest. Accordingly, the Commission Panel considers that subsection 5 of s. 44.2 is applicable to the Application, whereas subsection 44.2(6) is not.

1.2.3 ‘Cost effectiveness’ and the Demand Side Measures (DSM) Regulation

Subsection 44.2 (5)(d) requires the Commission to consider whether the EEC expenditures are “. . . cost-effective within the meaning prescribed by regulation, if any, . . .”.

On November 7, 2008, the Government issued Ministerial Order M271/2008 which attached B.C. Reg. 326/2008 - Demand-Side Measures Regulation. Section 3 of the DSM Regulation deals with the “adequacy” of a demand-side measures “plan portfolio” and section 4 of the DSM Regulation sets forth certain requirements with respect to the determination of whether such expenditures are “cost effective”. Section 2 of the DSM Regulation provides that the regulation applies only to ‘the authority’ (BC Hydro) until June 1, 2009, at which time the regulation will become more generally applicable. Accordingly the requirements of sections 3 and 4 are not applicable to Terasen’s current EEC Application.

1.2.4 BC Government's Energy Objectives

Subsection 44.2 (5)(a) of the Act requires the Commission to consider the "government's energy objectives" in considering whether to accept an expenditure schedule. The "government's energy objectives" are defined in section 1 of the Act as follows:

> "(a) to encourage public utilities to reduce greenhouse gas emissions;
>
> (b) to encourage public utilities to take demand-side measures;
>
> (c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
>
> (d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
>
> (e) to encourage public utilities to use innovative energy technologies
>
>> (i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or
>>
>> (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;
>
> (f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation…"

2.0 TERASEN'S PROPOSED EEC EXPENDITURES

Terasen is applying for approval of an increase in allowed expenditures for EEC activity for TGI and TGVI to a total of approximately $56.6 million over the three year Program Period 2008 to 2010, an increment of $48.062 million over currently approved DSM spending for the two utilities. (Exhibit B-1, p. 8)

The proposed EEC Expenditures, by Program Area, by Utility, are set out in the table below.

Table 1

($000)

Spend by Program Area 2008 -2010	**TGI**	**TGVI**	**Total**
Residential Energy Efficiency	8,552	734	9,286
Commercial Energy Efficiency	19,592	2,199	21,791
Residential Fuel Switching	1,332	2,367	3,699
Conservation Education and Outreach	11,068	2,767	13,835
Joint Initiatives	2,400	600	3,000
Trade Relations	1,200	300	1,500
Conservation Potential Review	400	100	500
Innovative Technologies, NGV and Measurement	2,400	600	3,000
Total	46,944	9,667	56,611

(Source: Exhibit B-1, p. 9)

Terasen states that it is most efficient for the Commission to approve the overall expenditure level, by utility, for the funding period rather than by approving the funding by program area or by individual program initiative. Terasen submits that this approach will allow it to respond quickly to changes within initiatives and to new opportunities that might arise, and will reduce the administrative burden related to EEC activity. (Exhibit B-1, pp. 50-51)

Terasen also submits that the energy savings from the EEC expenditures will result in savings with a present value of almost 10 million gigajoules ("GJs") over the lives of the various measures proposed, while fuel switching activity is estimated to result in approximately 2.3 million GJs of additional load. The anticipated present value of net energy savings is approximately 7.7 million GJs, not including potential savings arising from Conservation Education and Outreach, Joint Initiatives or Innovative Technologies, NGV and Measurement program areas. (Exhibit B-1, p. 10) Terasen further states that DSM expenditures at current levels would result in cumulative annual savings of 1.3 million (nominal, rather than present value) GJs by 2016, whereas the proposed expenditures would result in cumulative annual savings of approximately 6.4 million nominal GJs in the same time period. (Exhibit B-1, p. 11)

2.1 Residential and Commercial Energy Efficiency

Terasen developed its budget estimates for Residential Energy Efficiency, Commercial Energy Efficiency and Residential Fuel Switching based on work done in 2006 in its Conservation Potential Review ("CPR"). Those estimates were refined by Habart and Associates Consulting Inc. ("Habart") as described in Habart's September 2007 Report ("Habart Report") provided in Appendix 9 of the Application. (Exhibit B-1, p. 52) The Habart Report concluded that total DSM funding of approximately $35 million over the three-year period would be required. (Exhibit B-1, Appendix 9, p. 23)

Terasen states that "[t]he key finding of the CPR was the Achievable Potential" which is a measure of savings which could realistically be achieved within the study period. (Exhibit B-1, p. 45) The Achievable Potential from the CPR is outlined in the table below:

Table 2

CPR Findings

By 2015/2016, GJ per year	TGVI	Lower Mainland	Interior	Total
Residential EE	-369,000	-5,298,000	-1,847,000	-7,514,000
Commercial EE	-385,000	-1,396,000	-431,000	-2,212,000
Industrial EE	-32,430	-933,064	-924,210	-1,889,704
Subtotal	**-786,430**	**-7,627,064**	**-3,202,210**	**-11,615,704**
Residential Fuel Subsitution				1,453,000
Potential Annual Impact				**-10,162,704**

(Exhibit B-1, Table 4.1, p. 45)

Terasen states that "[t]he strategies outlined in this Application, and the expenditures for which approval is being sought, are based to a significant degree on the findings of the CPR and the subsequent work undertaken with Habart." (Exhibit B-1, p. E-3)

In discussing estimation of new dwelling heating loads, the 2006 CPR states that: "[d]iscussions with provincial government staff indicated that a number of changes to residential buildings are under consideration that could affect the thermal performance of British Columbia's new housing over the study period." The changes being considered include targets for new construction, including residential buildings and all commercial buildings (including apartments) and strategies to achieve improved thermal performance in related residential equipment and products, including furnaces, fireplaces, and windows. (Exhibit B-1, Appendix 1, p. 33)

2.1.1 Residential Energy Efficiency

Terasen proposes spending $9.286 million on Residential Energy Efficiency for both TGI and TGVI over the Program Period (Exhibit B-1, p. 55, Table 6.2b). The Residential Energy Efficiency program area includes both new construction and retrofit initiatives.

2.1.1.1 New Construction

For new construction, Terasen is proposing EnerChoice Fireplace and Energy Star Appliance initiatives. The EnerChoice Fireplace program will provide an incentive to customers who purchase and install an EnerChoice rated fireplace, insert or free-standing stove. The Energy Star Appliance program provides incentives for customers who use natural gas for domestic hot water ("DHW") heating to install Energy Star clothes washers and/or dishwashers. (Exhibit B-1, p. 59)

Terasen states "[t]he key decision makers in this market for the [new construction] programs . . . are builders and developers who build single family homes and row-houses" and ". . . new construction EEC portfolio in the residential market will include programs that encourage customers, whether they be individuals building a new home, or builders and developers, to install energy efficient appliances." (Exhibit B-1, p. 58) (emphasis in original)

2.1.1.2 Retrofit

For the residential retrofit market Terasen is proposing an Energy Star Heating System Upgrade program that will reprise earlier versions of this program, and will provide customers who install an Energy Star heating system a credit on their Terasen bill for gas service. Terasen's Application is based on funding for incentives for gas furnace upgrades in single family dwellings ("SFDs") and duplexes in the Terasen service territory. Terasen estimates upgrades to 5.3 percent of the stock of pre-1976 SFDs and duplexes or 8,180 furnace upgrades to the end of 2009. Terasen notes that due to expected new Federal government regulations requiring all furnaces sold in Canada to meet a minimum standard of 90 percent efficiency after December 31, 2009, this program will conclude prior to that date. (Exhibit B-1, pp. 59-60)

Terasen is also proposing EnerChoice Fireplace and Energy Star Appliance programs for the retrofit market as for the new construction market. The Hearth, Patio & Barbeque Association of Canada will provide assistance in promotional and educational aspects of the EnerChoice Fireplace program. (Exhibit B-1, p. 60)

The residential sector expenditures proposed by Terasen, by utility and program area are as follows:

Table 3

TGI and TGVI Energy Efficiency ($000)		**2008**	**2009**	**2010**	**Total**
TGI	New Construction	411	566	1,056	2,033
	Retrofit	2,495	2,658	1,367	6,520
	Sub total, TGI	2,906	3,224	2,423	8,553
TGVI	New Construction	130	156	232	518
	Retrofit	53	66	97	216
	Sub total, TGVI	183	222	329	734
	Total	3,089	3,446	2,752	9,287

Source: BCUC IR No. 1 Attach 56.2A

2.1.1.3 Commercial Energy Efficiency

Terasen is proposing to spend $21.7 million on commercial sector new construction and retrofit programs (Exhibit B-1, p. 60). The expenditure proposals were based on refinements of the following initial recommendations from the Habart report:

Table 4

TGI and TGVI Commercial Programs	**Spending 2008-2010 ($000) TGI**	**TGVI**
New Construction		
Efficient New Construction	5,297	727
Boilers	1,928	224
Water Heating	1,118	103
Subtotal - New Construction	**8,343**	**1,055**
Retrofit		
Boilers	7,395	1,074
Building Recommissioning	3,095	354
Next Generation Building Automation Systems	968	95
Demand Control Ventilation	1,795	-
High Efficiency Rooftop Units	239	17
Water Heat	2,032	254
Subtotal - Retrofit	**15,524**	**1,794**
Total Commercial Energy Efficiency	**23,867**	**2,849**

Source: Exhibit B-2, Attachment 56 2A TGVI and 56 2A TGI

2.1.1.4 New Construction

The commercial new construction program is aimed at all new construction "…which might use natural gas space and water heating." Terasen states that "…the immediate opportunities are likely to be Multifamily Dwellings ("MFDs") and Commercial office space" and may also include some institutional buildings. (Exhibit B-1, p. 61) Terasen lists some potential areas for activity in the commercial new construction sector, and notes that program design in this sector is complex, so the program activities listed in the Application are merely summaries.

Terasen states “[t]he key decision makers in this market are owners including: governments; builders/developers; architects; engineers; interior designers; mechanical consultants; and contractors.” (Exhibit B-1, p. 61)

The new construction energy efficiency program areas include initiatives aimed at:

- Efficient New Construction Design and High Insulation Technology for windows;
- Condensing and near condensing boilers; and
- Instantaneous and condensing DHW heaters and drain water heat recovery.

(Exhibit B-1, Table 6.3.2, p. 61)

2.1.2.5 Retrofit

Terasen’s commercial retrofit program is aimed at all commercial and industrial buildings with existing natural gas space and water heating equipment. Terasen again notes that, due to the complexity of programs in this sector, it has merely summarized areas of program activity and states “[m]ore detailed program development work must be completed by [Terasen] in conjunction with industry groups before these programs are rolled out.” (Exhibit B-1, p. 62)
Commercial retrofit energy efficiency program area activity includes initiatives for:

- Condensing and near condensing boilers
- Building Recommissioning
- Next Generation Building Automation Systems (“BAS”)
- High Efficiency (“HE”) Rooftop Units
- Instantaneous and condensing DHW boilers and heaters
- For TGI only, Terasen is proposing to add: demand control ventilation for large and medium commercial buildings and drainwater heat recovery.

(Exhibit B-1, p. 62, Table 6.3.2a)

Terasen states that commercial sector programs are intended to offer qualified customers a menu of programs from which to choose and that Terasen staff will work with participants in selecting the most appropriate program and/or component. (Exhibit B-1, p. 63)

Intervenor Positions

BCOAPO takes issue with the relative allocation of spending as between proposed residential and commercial customer groups. BCOAPO notes that residential customers make up 90 percent of Terasen's total customers and 38 percent of its total volume, whereas commercial customers represent only 9.7 percent of its customer base and 26 percent of its total volume. (BCOAPO Argument, p. 12)

Commission Determination

The Commission Panel notes BCOAPO's comments as well as the CPR evidence indicating that some 70 percent of the Achievable Potential savings are associated with the residential sector. Terasen has included residential market MFDs in its Commercial EE program, which, in the view of the Commission Panel, may also have significant potential for low income housing initiatives. Terasen indicates that it will re-direct funding amongst programs based on customer response, thus enabling funding balancing between Residential and Commercial programs as appropriate.

The Commission Panel finds the design of Terasen's Residential and Commercial EE programs to be reasonable, flexible and in the public interest, and accepts the expenditure proposals for these program areas.

2.2 Residential Fuel Switching

Reduction in Greenhouse Gas ("GHG") emissions is advanced by Terasen as a benefit in support of residential fuel switching for TGI. The stated premise is that the substitution of natural gas for electricity will reduce overall GHG emissions in the short term, by increasing the amount of electricity available to BC Hydro to meet domestic load, thereby reducing its dependence on imported power or, alternatively, allowing it to increase exports of clean power, thus enabling a reduction in the regional use of gas or coal-fired power. Terasen submits, over the longer term, to the extent BC Hydro is able to meet its load requirements, excess clean generation could be exported, displacing the use of gas and/or coal-fired generation in the region (Western Interconnection). (Exhibit B-1, p. 63; Terasen Reply, p. 5)

Terasen states that "[t]he primary objective of the fuel-switching offers is to promote the most optimal balance in energy share between electricity and natural gas, preserving BC Hydro's generation and transmission systems for its [sic] highest value – in running lights, computers and other technology." (Exhibit B-1, p. 64)

Terasen proposes to spend $3.7 million in the residential fuel switching program area. It is proposing that only new construction fuel switching programs be offered in the TGI service area but that both new construction and retrofit fuel switching programs be offered in the TGVI service area.

Terasen proposes to spend the following amounts on fuel switching programs annually, over the Funding Period.

Table 5

Residential Fuel Switching Programs

Program		**Initiatives**	**TGI**	**TGVI**
New Construction				
	Natural Gas Water Heating	NG DHW	319	693
	Natural Gas Appliances	NG Range	1,013	50
		Sub Total	1,332	743
Retrofits		NG Dryer		38
	Natural Gas Appliances	FS Range	-	247
		FS Dryer	-	247
	Furnace Fuel Substitution	Furnace	-	766
	Fireplace Fuel Substitution	EnerChoice Fireplace	-	326
		Sub-total		1624
		Totals	1332	2367

Source: Exhibit B-2, Attachments 56.2A 2 (TGI) and 56.2A 4 TGVI

New Construction

All new construction expenditures involve fuel switching from electricity. Only the Retrofit programs, which are limited to Vancouver Island, involve potential fuel switching from propane, oil or wood in addition to electricity. Terasen states: "[i]t is very challenging to separate out proposed expenditures for fuel switching from electricity to natural gas from vs. [sic] proposed expenditures for fuel switching from non-electric sources to natural gas, as there are a number of potential energy sources for the proposed TGVI residential retrofit program, and …[it] cannot predict the proportion of participants switching from each energy source." (Exhibit B-5, BC Hydro 1.1.1)

Terasen proposes fuel substitution incentive programs to encourage the use of natural gas in new construction projects for installation of natural gas domestic hot water heaters in the TGVI service area and to install a natural gas range and/or dryer in both the TGI and TGVI service areas. (Exhibit B-1, p. 64)

Retrofit

Incentive funding for fuel substitution retrofits is only contemplated for TGVI, as many households in its service territory still use wood, propane or fuel oil for space heating and fireplaces.

The proposed programs include incentive payments for:

- Switching to natural gas for space heating and for installing Energy Star equipment. Terasen states that "the current regulatory regime for TGVI does not allow Terasen to offer customers who switch to natural gas an incentive to install Energy Star equipment." (Terasen proposes that it be able to offer both, but also advises that it would restrict the incentive to furnaces and boilers rated Energy Star.);
- Installation of an EnerChoice-rated fireplace, insert or free-standing stove; and
- Replacement of existing electric or propane ranges and dryers with gas appliances.

(Exhibit B-1, p. 65)

Intervenor Positions

BCOAPO strongly opposes the inclusion of any expenditures associated with fuel switching away from electricity to natural gas in Terasen's EEC portfolio. BCOAPO argues that there is no evidence as to an "optimal balance" as between electricity and natural gas and suggests that a movement away from (clean) electricity to a fossil fuel would not be part of such optimal balance. (BCOAPO Argument, p. 10)

BC Hydro filed the evidence of Randy Reimann, P. Eng., its manager of Resource Planning, wherein he contradicted Terasen's assertion that fuel switching away from electricity to natural gas would reduce the need for BC Hydro to import electricity from other jurisdictions which rely on coal or natural gas for generation. Mr. Reimann stated: "[t]here is no medium to long term linkage between fuel switching from electricity to natural gas and a change in BC Hydro's need for importing electric energy or ability to export such energy." (Exhibit C2-6, Direct Testimony of Randy Reimann, p. 2, Q.7)

BC Hydro also filed the evidence of Patrice Rother, its manager of Environmental Strategy in the Safety, Health and Environmental group. Ms. Rother reviewed recent GHG-related legislative and policy developments including the B.C. Greenhouse Gas Reduction Targets Act ("GGRTA"), the B.C. Climate Action Plan and the joinder of British Columbia into the Western Climate Initiative and highlighted a number of areas of uncertainty surrounding how the WCI GHG trading scheme will align with the GGRTA legislated targets and other Chinook Action Plan action items on a regional basis. (Exhibit C2-6, Direct Testimony of Patrice Rother pp. 2-3, Q. 8, 11)

Commission Determination

While the Commission Panel notes the comments of Terasen regarding potential GHG benefits of fuel switching, particularly away from fossil fuels with a higher carbon content than natural gas, the Commission Panel is not convinced that expenditures on fuel switching and load building away from electricity can be properly considered in a portfolio of EEC programs at this time. The Commission Panel agrees with the comments of the BCOAPO that the "optimal balance" as between natural gas and electricity has not been established. The Commission Panel also finds that the efficiency of other energy sources over and above that of electricity has not been adequately established.

The Commission Panel also notes that natural gas does have a GHG impact which is not present in clean domestic electricity and that one of the government's energy objectives is "to encourage public utilities to reduce GHG emissions." The Commission Panel accepts the evidence of

Ms. Rother that there is considerable uncertainty, at this time, surrounding how various government initiatives will align on a regional basis. The Commission Panel finds that Terasen has not provided sufficient evidence to persuade the Panel, on a balance of probabilities, that a regional approach should be adopted as a justification for EEC expenditures aimed at substituting natural gas as a fuel to replace electricity.

The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than that of natural gas. Expenditure programs specifically directed at encouraging fuel switching away from electricity are rejected, as are Incentive payments for appliances for which an Energy Star rating is not available. However, expenditures are accepted for incentives to install Energy Star and EnerChoice equipment and appliances for customers who, at their own initiative, wish to switch to natural gas as the fuel of choice.

2.3 Conservation Education and Outreach

This proposal is in addition to program-specific education and outreach funding, and relates to non-program-specific activities, as set out below.

- Terasen's proposed budget for Conservation Education and Outreach (CEO) was developed in consultation with Wasserman + Partners Advertising ("Wasserman"). Terasen proposes a total CEO expenditure of $13.835 million in the 2008 to 2010 period which is 24 percent of the total EEC proposed expenditures of $56.611 million. The Wasserman proposal states that the planned messaging will educate the public about Terasen's EEC program and related activities.

(Exhibit B-1, Appendix 8)

Terasen was requested to describe the specifics of the CEO programs and responded that these initiatives ". . . have not yet been fully developed, however, as outlined on page 65 of the Application, they are projected to include:

- Stakeholder industry group activities, such as first time homebuyers seminars
- Public outreach by “Team Terasen”
- Support for conservation education within the school system
- Energy Forum
- Conservation communications, as outlined in Appendix 8 in the Application.”

(Exhibit B-2, BCUC 1.28.1)

The entire proposed $13.835 expenditure for the CEO Program Area is taken by the Conservation communications initiative of the CEO Program. $11.550 million or 83 percent of the $13.835 million is allocated to Mass Media Advertising and Production over the three year expenditure period. (Exhibit B-1, Appendix 8)

Terasen did not submit any details or expenditure estimates for the first four program initiatives described above.

Terasen proposes to attribute the CEO expenditures in each year equally between the Residential and Commercial Energy Efficiency programs, with none of the CEO expenditures being attributed to other Program Areas such as Fuel Switching or Trade Relations. (Exhibit B-1, p. 54)

Terasen states: “EEC expenditures will be efficient, with non-incentive costs not exceeding 50% of the expenditure in a given year.” (Exhibit B-1, p. 47, #3) Terasen does not provide any further evidence supporting the implication that, merely by not exceeding 50 percent of the total, non-incentive, expenditures, the balance represents efficiency in expenditures.

<u>Intervenor Positions</u>

BCOAPO submitted that “The Application’s education and outreach component is disproportionately large, and inappropriately treated as an asset to be amorti[s]ed over 20 years.” (BCOAPO Argument, p. 14)

BCSEA-SCBC submitted the evidence of John J. Plunkett of Green Energy Economics Group, Inc. The Commission Panel reviewed Mr. Plunkett's qualifications and experience and accepts him as an expert with respect to the matters his testimony addresses in this Application.

Mr. Plunkett proposes that the CEO should be reduced by 50 percent, and the amount by which the funding is reduced be redirected to the residential and commercial efficiency programs.
Mr. Plunkett notes that while building a conservation 'ethic' in British Columbia is laudable, the primary purpose of the CEO expenditures should be to support the efficiency programs.
(Exhibit C5-5, pp. 18, 19)

Commission Determination

The Commission Panel finds that Terasen has not provided sufficient evidence to support either the $13.835 million total proposed EEC expenditures, or the allocation of some 84 percent of that amount to mass media advertising and production. The Commission Panel notes that the Commercial component comprises some 70 percent of the total expenditures in the combined Residential and Commercial Energy Efficiency program areas, to which the CEO costs have been attributed equally. The Commission Panel also notes Terasen's comments, quoted above, with respect to the key decision makers in both the new and retrofit commercial markets. The Commission Panel considers both these markets to be significantly more narrow and focused than markets which may warrant the use of mass media approaches to communication.

The Commission Panel also notes that Terasen's evidence did not include any discussion of bill stuffers or other communication methods.

The Commission Panel agrees in part with Mr. Plunkett's proposal, and considers that, while public education is an appropriate activity in support of the EEC objectives, the evidence is not sufficient to support either the full amount proposed or the allocation of the proposed CEO expenditures. The Commission panel does not agree with Mr. Plunkett's suggestion that the funding reduction of the CEO expenditures be redirected to the energy efficiency programs. The Commission Panel finds the evidence sufficient to establish that there is a benefit to some CEO expenditures and accepts 50 percent, $6.918 million, as reasonable.

Terasen is directed to review the CEO program with a view to:

- altering the program to allocate funds away from the mass media campaign and to include other initiatives, with particular attention paid to conservation education within the school system and affordable housing initiatives;
- addressing the apparent imbalance of the residential to commercial expenditure ratio, approximately 30:70, in comparison to the ratio of residential to commercial Achievable Potential GJ impact of approximately 77:23 (Exhibit B-1, p. 45);
- reconsidering the apparent lack of communication expenditures directed in a focused manner to the Commercial Energy Efficiency program,
- reconsidering appropriate attribution of CEO costs to Program Areas and initiatives, and any related impact on Total Resource Cost calculations and rate impacts.

2.4 Joint Initiatives, Trade Relations, 2009 CPR, and Innovative Technologies, NGV and Measurement

2.4.1 Joint Initiatives

Terasen is requesting that $1.0 million per year be approved for the development of Joint Initiatives as they arise. Initiatives that Terasen states it will, or may pursue if the funding is approved, include: support for audits for a Provincial Home Retrofit Program, DSM for affordable housing, building labeling, and community action on energy efficiency. (Exhibit B-1, pp. 66-68)

2.4.1.1 Audits

The "audit" joint initiative involves providing financial assistance to customers by paying for the cost of a pre or post upgrade audit, both of which are necessary for participation in the federal government's "Eco-Energy" program. This initiative would support the provincial government's expressed intention to implement a province-wide home retrofit program, "LiveSmartBC", to complement the federal government initiative. The provincial program does not contemplate paying the cost of post-retrofit audits, and Terasen sees an opportunity to provide full or partial funding to enable more of its customers to participate in the programs. (Exhibit B-1, pp. 43, 67)

2.4.1.2 Affordable Housing

Terasen states that "[t]he Ministry of Energy Mines and Petroleum Resources has asked that the Terasen Utilities lead a working group on DSM for Affordable Housing, the goal of which is to find ways and means to deliver Energy Efficiency to the Affordable Housing sector in B.C. and that such group has been convened. Terasen proposes to fund its participation in any resulting DSM incentive program from the Joint Initiatives Program allocation. (Exhibit B-1, p. 67)

2.4.1.3 Labeling

A further joint initiative which Terasen proposes is to co-fund a pilot project to label homes and buildings with an energy consumption/efficiency rating. Terasen states that this will assist in informing the public and promoting energy conservation and will enable comparisons as between different gas-heated homes.

2.4.1.4 Community Action

Terasen also proposes to make a financial contribution to the pool of funds to which municipalities can apply under the "Community Action on Energy Efficiency" initiative for financial and research support to advance energy conservation and efficiency in their areas, through policy action and public outreach. (Exhibit B-1, p. 68; The BC Energy Plan 2007- Policy Action #9)

Intervenor Positions

BC Hydro supports the Joint Initiatives funding requested. (BC Hydro Argument, p. 5)

BCOAPO argues that this area of the EEC is "drastically under-funded if any meaningful [low-income energy efficiency program ("LIEEP")…is to be developed." (BCOAPO Argument, p. 7)

BCSEA-SCBC argues: ". . . while the four initiatives under the Join Initiatives program area may be worthwhile" they do not satisfactorily address the need for better integration of Terasen's programs with electrical DSM programs as identified by the BCSEA-SCBC expert, Mr. Plunkett. (BCSEA-SCBC Argument, pp. 12-13) Mr. Plunkett recommends that Terasen should be directed to redesign programs by streamlining them and better integrating them with electric efficiency programs. (Exhibit C5-5, p. 5)

Commission Determination

The Commission Panel accepts the expenditures requested for the Joint Initiatives Program area. The Commission Panel notes the comments of the BCOAPO and agrees that the Affordable Housing Initiative appears to be under-funded, particularly given that no portion of the requested global amount for Joint Initiatives is specifically dedicated to Affordable Housing. The Commission Panel also notes that the DSM Regulation which does not yet, but will, apply to Terasen requires that a public utility's plan portfolio include "a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption". The Commission Panel therefore directs Terasen to proceed with its Joint Initiative relating to Affordable Housing and encourages Terasen to consider re-allocating funding from other approved areas of its overall spending as may be suitable.

The Commission Panel concurs with Mr. Plunkett's recommendation, and considers the Joint Initiatives Program to be an appropriate area from which funds should be used to aggressively pursue integrating Terasen's EEC programs with those of the electric utilities in British Columbia. The Commission Panel's view is that integrating the efforts of gas and electric utilities will better encourage customers to take advantage of the programs by eliminating unnecessary duplication in communication, applications, audits and similar time consuming activities.

2.4.2 Trade Relations

The Trade Relations program area is aimed at the support and education of skilled trades, equipment manufacturers, distributors, suppliers and retailers, appliance and equipment salespeople and Realtors. The $1.5 million in funding being requested for Trade Relations with this Application is to support the activities of a Terasen Utilities staff member focused on Trade Relations as it relates to energy efficiency.

Commission Determination

The Commission Panel takes note of Terasen's descriptions of the key decision makers in each of the Residential and Commercial EE programs, referred to previously, as well as the references to the complexity of the commercial new construction and retrofit sector programs and resulting paucity of detail for those program areas. (Exhibit B-1, p. 61)

The Commission Panel considers that the Trade Relations program area expenditures represent a significant duplication of the Residential and Commercial Energy Efficiency programs' non-incentive costs. As noted in the Application, the Energy Efficiency programs will significantly increase the interactions as between Terasen and its customers, and therefore increase "the opportunities for [Terasen] to communicate general conservation information in addition to program-specific information..." (Exhibit B-1, p. 46) The Commission Panel finds the evidence with respect to the details of the Trade Relations program area to be insufficient, and accordingly, this area of expenditure is rejected.

2.4.3 Innovative Technologies, NGV and Measurement

Terasen states that it is in a unique position to foster and further the deployment of forward-looking low carbon technologies, including measurement technologies, and is therefore seeking funding with this Application, specific to this arena. (Exhibit B-1, p. 69)

Terasen states that "[t]he amount for Innovative Technologies, NGV and measurement will need to be refined – if an effective program in Innovative Technologies, NGV and Measurement can be developed over the funding timeframe, the Companies wish to have the ability to fund such a program over the funding timeframe." (Exhibit B-1, pp. 53, 69) Terasen states that the activity in this area would be in the nature of pilot programs, with limited time frames, geographic areas and numbers of installations. The Companies indicate that they would pursue technologies with the same underlying characteristics:

- Each promotes the efficient use of natural gas through sustainable design;
- None are currently a mainstream technology;
- Each offers the potential for at least a 10 percent GHG benefit.

Energy efficiency technologies the Companies would intend to pursue include:

- Residential
  - hydronic based heating systems;
  - Integrated energy systems providing both space heat and DHW;
  - Solar thermal assisted space or DHW systems;

- Commercial
    - hydronic based heating systems;
    - Solar thermal assisted space or DHW systems.

(Exhibit B-1, p. 73)

Terasen states that it would aim fuel-substitution initiatives at both new construction and retrofit markets in both the TGI and TGVI service areas, and notes that fuel-substitution in this category refers to the displacement of natural gas using cleaner renewable technologies. The Companies state that more detailed program development work must be completed by Terasen in conjunction with industry groups before programs are rolled out or funding is allocated. (Exhibit B-1, p. 74)

Commission Determination

The Commission Panel considers that Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions.

However, as noted above, Terasen acknowledges that further refinement of this program is required and indicates uncertainty as to whether an effective program can be developed over the funding timeframe. The Commission Panel finds that there is insufficient evidence with respect to the nature and scope of the proposed program, and accordingly rejects the Innovative Technologies, NGV and Measurement program expenditures at this time. Terasen may wish to bring forward projects in this program area for consideration as they become more fully developed.

2.5 Conservation Potential Review Update

The Terasen Gas April 2006 Conservation Potential Review (CPR) was a comprehensive planning document prepared for TGI to use for:

- Developing a long range energy efficiency and fuel choice strategy;
- Designing and implementing energy efficiency and fuel choice programs;
- Assessing the impact of energy efficiency and fuel choice programs on both peak and annual loads; and
- Setting annual efficiency and fuel choice targets and budgets.

(Exhibit B-1, Appendix 1, page E-1)

The 2009 CPR estimate of $0.5 million is based on the cost to perform the previous CPR, approximately $300,000, plus an allowance for the kind of work done by Habart to refine the CPR results into a DSM program. (Exhibit B-1, p. 53) The updated CPR would be received in 2010 and would form the basis for an application to the Commission for EEC funding for the period 2011 to 2014. (Exhibit B-1, p. 69) It also includes an allowance of $100,000 for cost inflation from the last CPR. (Exhibit B-2, BCUC 1.21.1)

The CPR Program is discussed at Section 4 of the Application, including an illustration of the CPR Process Flow, and a table summarising the potential annual impact identified by the 2006 CPR. The 2006 CPR identifies a gross impact [consumption reduction] by 2015/2016 of 11.615 million GJs, and a Potential Annual Impact of 10.163 million GJs after adding back 1.453 million GJs of additional load attributed to the residential fuel switching program. The gross impact number includes 1.890 million GJs for Industrial Energy Efficiency (EE). Separate programs for Industrial EE are not specifically included as part of the Application. (Exhibit B-2, pp. 44-46)

The detailed 2006 CPR report is included in the Application. (Exhibit B-2, Appendix 1)

Intervenor Positions

BCSEA-SCBC supports Terasen's proposal for approval of expenditures for an update of the CPR to form the basis for Terasen's "next tranche of EEC funding for the period 2011 to 2014." (BCSEA-SCBC Argument, p. 15)

BC Hydro supports Terasen's evidence with respect to the CPR and also the program element in the Application for additional funding for a 2009 update of the CPR. (BC Hydro Argument, p. 5)

Commission Determination

The Commission Panel considers the CPR to be an important tool for use in developing, supporting and assessing this and future EEC/DSM expenditure Applications. The Commission Panel accepts the Application's CPR update expenditure proposal.

The Commission Panel anticipates that Terasen will be able to develop a stronger and more transparent linkage between the CPR, the development of programs arising from the CPR and their proposed costs in any future EEC/DSM Applications.

2.6 The Industrial Sector

Terasen has not included energy efficiency (EE) initiatives for industrial customers in the Application. Terasen discusses its rationale for not planning for EE programs specifically for the industrial sector at Section 6.10 of its Application, Exhibit B-1, p. 78.

The CPR study conducted by Marbek Resource Consultants Ltd. and Willis Energy Services Ltd. (Marbek) concluded that:

> "The study findings confirm the existence of significant potential cost-effective natural gas efficiency improvements in B.C.'s manufacturing sector. In the "most likely" and "upper" achievable scenarios those energy efficiency improvements would provide between about 1,900 and 2,600 thousand GJ/yr. of savings in FY 2015/16. The same energy efficiency improvements would also provide reduced GHG emissions of approximately 80,000 to 112,000 tonnes per year as well as peak day load reductions of approximately 20 to 20.5 thousand GJ.
>
> Two particularly significant opportunities are identified in the study results:
>
> - Energy efficient boilers for the greenhouse and food processing facilities in the Lower Mainland.
> - Energy efficient kilns for sawmills and planer mills in the Interior."
>
> (Exhibit B-1, Appendix 1, p. 75)

<u>Intervenor Positions</u>

MEMPR provided a Letter of Comment stating: ". . .the Ministry has an interest in seeing Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. ("the Companies") expand their demand-side management activities. The Ministry notes the absence of specific demand-side measures for the industrial sector in the Application. The Companies may be missing significant conservation and efficiency gains." (MEMPR Letter of Comment, Exhibit C1-4, p. 1)

The Ministry also submitted that the Commission should include a number of determinations in its Decision with respect to the processes and timing of development of DSM measures for the manufacturing sector.

BCSEA-SCBC concurs with MEMPR's recommendation. (BCSEA-SCBC Argument, p. 16)

Terasen submits that "a cautious approach is warranted in considering delivering incentives to industrial customers at a high enough dollar level to spur participation adequate to ensure a positive TRC. Both of these options expose customers to risk. The Terasen Utilities will continue to explore opportunities for industrial DSM and will bring forward a proposal if they regard expenditures as being warranted and in the interests of customers." (Terasen Reply, p. 17)

Commission Determination

The Commission Panel considers that the omission of an industrial sector program in Terasen's EEC Application is a significant and unfortunate shortcoming in Terasen's stated efforts to support the BC Energy Plan ("Energy Plan") Policy Actions (Exhibit B-1, Appendix 6) with respect to Energy Efficiency in the industrial sector. The Commission Panel takes particular note of Terasen's specific exclusion of EEC Policy Action 8, which addresses the development of an "Industrial Energy Efficiency Program". (Exhibit B-1, p. 40; Energy Plan, p. 39)

The Commission Panel takes note of the MEMPR Letter of Comment, and directs Terasen to commence the planning process for the development of an industrial EE program and to file a report outlining the process contemplated and scheduling of the development plan with the Commission for review within 90 days of this Decision. The matters addressed in the report should include those raised by MEMPR in Exhibit C4-1.

3.0 ASSESSMENT CRITERIA AND ACCOUNTABILITY

Terasen believes that the benefit-cost ". . . results for the proposed EEC expenditure in this Application are under-stated, because the benefits used in the calculations include free-riders, effectively reducing the net energy savings, and exclude attribution effects, as well as excluding savings from the proposed expenditure on Joint Initiatives, Trade Relations, Conservation Education and Outreach and Innovative Technologies, Measurement and NGV. However, even with this approach, which could be considered conservative, the Total Resource Cost test result for the EEC portfolio as a whole is positive, with a ratio of 2.9., and a net financial benefit of $139.4 million. If free rider effects are excluded, as the Companies are proposing, the EEC portfolio has a TRC ratio of 3.1 and a net financial benefit of $165.1 million." (Exhibit B-1, pp. 87, 88)

3.1 Portfolio Approach

Terasen proposes a "portfolio approach" to the benefit-cost analysis which involves assessing the cost effectiveness of the EEC portfolio as a whole, "on an overall combined basis, rather than on individual initiatives or program areas." (Exhibit B-1, p. 82) Terasen proposes that the portfolio as a whole maintain a TRC ratio of 1.0 or better to allow it to include programs which, on an individual basis, may not have such a ratio in the short term, but have longer term potential to achieve the ratio. This approach would also allow Terasen to offer programs to customers in service areas which would otherwise not have sufficient customer usage to support the necessary TRC ratio. (Exhibit B-1, pp. 11-12)

<u>Intervenor Positions</u>

Mr. Plunkett indicates that judging economic performance at the portfolio level only is "problematic". (Exhibit C5-5, p. 14) He recommends that Terasen establish the cost-effectiveness of each measure and project. (Exhibit C5-5, p. 15)

Terasen states in reply that it is not proposing that economic performance be judged only at the portfolio level and that Mr. Plunkett has mischaracterized its proposal.

Terasen states that “[t]he energy efficiency and fuel switching programs would be planned and evaluated on the TRC, the RIM test, the Utility Cost (“UC”) test and the Participant test, and the overall portfolio TRC test results would have to be greater than 1.0 to proceed.” (Exhibit B-1, p. 83)

However, Terasen also states that it is “not proposing any thresholds with respect to the RIM test, the UC test and the Participant test. In the absence of such thresholds, [it is] not comfortable stating that an activity would proceed or not based on RIM, UC and Participant test results.” Rather, Terasen proposes that “the overall portfolio level TRC must be maintained at 1.0 or greater.” (Exhibit B-4, BCUC 2.19.1)

Commission Determination

The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level, discussed below, of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives. Consequently, it is important for the components of any portfolio to be capable of analysis on an individual basis. The Commission Panel directs that Terasen include in its annual EEC Report to the Commission the results of the RIM, UC, TRC and Participant tests for each proposed DSM in its portfolio, and provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0.

Total Resource Cost Test

Terasen proposes that the benefit-cost tests be used to evaluate its programs as outlined in the "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects", which is included in Exhibit B-1 as Appendix 12 ("the California Standard Practice Manual"). (Exhibit B-1, p. 82)

The California Standard Practice Manual describes the Total Resource Cost Test as a cost-effectiveness test which "measures the net cost of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs." (Exhibit B-1, Appendix 12, p. 18)

The "benefits" portion of the TRC test is made up of the avoided supply costs, valued at their marginal cost, for periods when a load reduction results. These costs are "calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant." (Exhibit B-1, Appendix 12, p. 18)

The "costs" portion of the TRC test is made up of the program costs paid by the utility and the participants plus any increase in supply costs for periods when load is increased. This is a broad category, and includes all equipment costs, installation, operation and maintenance costs, cost of removal (less any salvage value), and administration costs, regardless of who pays, less any tax credits. For fuel substitution programs, costs also include any increase in the supply costs of the utility providing the chosen fuel. (Exhibit B-1, Appendix 12, p. 18)

The benefit-cost ratio is the ratio of discounted total program benefits to discounted total program costs over a specified period of time. A benefit-cost ratio greater than one indicates the program is beneficial, on the basis of the TRC test. (Exhibit B-1, Appendix 12, p. 19)

Intervenor Positions

BCOAPO prefers the "Societal test" over other cost-benefit tests which it argues "do not capture the non-economic benefits of DSM programs". (BCOAPO Argument, p. 4)

According to the California Standard Practice Manual, the "Societal test" is a variant of the TRC test. It differs in that it looks at society as a whole as opposed to the utility's service territory and includes the effects of externalities, such as environmental implications. It also excludes tax credit benefits and uses a "societal" discount rate.

Mr. Plunkett notes in his evidence that: "[i]ncluding external social and environmental benefits in calculating DSM cost-effectiveness would be to apply the societal test, not the total resource cost (TRC) test. Other jurisdictions such as Vermont and New York apply the societal test as the threshold determinant of DSM cost-effectiveness. Explicitly valuing social and environmental externalities in DSM cost-effectiveness will lead to more efficient resource allocation – and greater societal net benefits – than the economically inferior policy of pursuing a portfolio benefit/cost ratio under the TRC test of 1.0." (Exhibit C5-7, BCUC 1.5.2)

Commission Determination

The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognising that societal factors have significance, the Commission Panel views many of these factors as being rather subjective and difficult to measure. The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective. While the DSM Regulation is not in effect for the purposes of this Decision, the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such.

3.2 Free Riders

Terasen seeks certain changes to the cost-benefit analysis undertaken in respect of EEC expenditures, including a proposal to ". . . eliminate the requirement to include free riders in cost-benefit tests, as the energy and emissions reduction goals of the government are absolute goals and do not consider free ridership effects." (Exhibit B-1, p. 16)

The Application defines free riders as ". . . customers who participate in a program, but would have undertaken the same conservation actions even if the program were not offered". Terasen's proposal with respect to free riders includes two tables illustrating an estimated TRC benefit for the EEC Portfolio of $165.149 million, excluding the effects of free riders, and of $139.448 million, including the effects of free riders, a difference of $27.701 million. Terasen's discussion concludes with the view that ". . . the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan." (Exhibit B-1, pp. 85-86)

Terasen responded in some detail to Information Requests concerning Free Riders, including the statements that "[f]ree riders are one of the most-debated aspects of DSM cost-benefit tests as they are challenging to establish" and "[e]stimating free rider rates . . . is more of an art than a science." (Exhibit B-2, BCUC 1.3.1)

It is Terasen's view that "it should be the outcome [energy consumption reduction] that matters, not the way in which it was achieved." (Exhibit B-1, p. 86) Terasen states: ". . . . [Government] GHG reduction goals make no mention of net-to-gross ratios – in fact they could be considered "gross" GHG reduction goals, and presumably it is gross energy savings that will be counted towards achieving those goals. It makes sense to align gross estimations of energy savings from utility DSM programs with government's gross GHG reduction goals." (Exhibit B-2, BCUC 1.3.1)

Terasen notes that "[w]hile it is possible that estimated free rider rates may be higher than forecast, it is also possible that free rider rates may be lower than forecast." (Exhibit B-2, BCUC 1.46.1)

Intervenor Positions

With respect to the free rider issue, BCSEA-SCBC's expert Mr. Plunkett states:

> "[Terasen's] proposal would depart from well-established Commission practice of accounting for savings from program free riders. This not only distorts economic assessment but is also inconsistent with resource planning, since it will overstate how much Terasen should expect to reduce energy supply requirements. It will also distort program design, especially in appliance and equipment replacement markets where the high-efficiency market penetration can change rapidly. Ignoring free ridership would tend to prevent adjustments in minimum qualifying efficiency levels due to a higher-efficiency market baseline." (Exhibit C5-5, pp.15, 16)

Mr. Plunkett's concluding recommendation included directing Terasen to modify its plan to "[d]evelop market net-to-gross ratios for programs based on estimates of free-ridership and spillover effects incorporated into program planning and design." (Exhibit C5-5, p. 23)

BCSEA-SCBC does, however, agree with Terasen that "the inclusion or exclusion of free riders from the analysis makes no practical difference in evaluating the acceptability of this specific EEC plan on an overall basis" although it notes that "failing to incorporate the free-rider factor can distort program design." (BCSEA-SCBC Argument, p. 19)

BCOAPO expresses the view that ". . . free ridership has the effect of over-crediting EEC programs. BCOAPO agrees that measuring free ridership is difficult, but this difficulty does not mean that it is appropriate to set it to zero." BCOAPO concurs with Mr. Plunkett's views with respect to the free rider issue. (BCOAPO Argument, p. 13)

Commission Determination

The Commission Panel notes the position of Terasen, and the acknowledgements of BCOAPO and BCSEA-SCBC that, in the case of the Application, the free rider issue has no immediate practical impact, as the portfolio level TCR results calculated either with or without inclusion of the free rider effect is well above the 'break-even' threshold of 1.0. However, the Commission Panel does consider that this issue is likely to become a factor as the DSM initiatives of Terasen become more fully developed and refined, and therefore should be addressed in this Decision.

The Commission Panel does not agree with Terasen's position that ". . . the inclusion of the effects of free riders in the cost-benefit test for EEC programs distorts the value of EEC programs and is counter to the objectives of the energy plan." (Exhibit B-1, pp. 85-86) The Commission Panel considers that it would be an unacceptable distortion to measure the effectiveness DSM programs by giving credit to the programs for consumption reductions which, based Terasen's own definition (quoted above), would have taken place absent the incentive program.

The Commission Panel rejects Terasen's proposal to exclude the free rider factor from program effectiveness (TRC) calculations.

3.3 Attribution to Regulatory Changes

Terasen submits that once a proposed regulation and implementation date for minimum efficiency standards for an appliance, building or energy system is announced by a regulating body, it be permitted to attribute savings to market transformation programs for that particular appliance, building or energy system in its cost benefit tests at that time. The proposal involves attributing the savings to the program over a five year span, with adjustment for the level of Terasen's support for the market transformation and the level of financial contribution by others.

Terasen submits that it is reasonable to include attribution savings in a cost-benefit test, particularly in light of the newly issued DSM Regulation. The Regulation permits the Commission to include in the benefit of measures proposed a proportion of the savings resulting from the increased market share of a regulated item because of the commencement and application of a specified standard with respect to the regulated item. (Terasen Argument, p. 39; Exhibit B-1, p. 12; Exhibit B-1, p. 16)

The attribution rates proposed by the Company, for which it is seeks approval with this Application, for any such future regulation are outlined below.

Table 6
Attribution Rates

Regulation Year	Percentage of Savings Attributed to Program
1	50
2	40
3	30
4	20
5	10

Source: Exhibit B-1, p. 87

Intervenor Positions

BCSEA-SCBC's concern with respect to the attribution concept is based on Mr. Plunkett's evidence that it can distort program design. As with the free-rider factor, BCSEA-SCBC favours the use of net-to-gross ratios. (BCSEA-SCBC Argument, p. 20)

BC Hydro submits that "Terasen Utilities' position on attribution of savings from codes and standards to utility DSM programs is arbitrary and will result in an unrepresentative view of the benefits (higher or lower) associated with some programs." BC Hydro further submits that "[a]ttribution of savings from codes and standards should be evaluated on a case-by-case basis" and that "the attribution rate should reflect the level of support for market transformation", arguing that Terasen's "position on attribution goes against this approach." (BC Hydro Argument, p. 17)

BCOAPO states ". . . the DSM regulation 4(7) allows for the Commission to include a proportion of the benefit that, in the Commission's opinion (not the Applicant's) will increase market share only between the time that a specified standard has been announced, and the time that it commences. Any attribution beyond that will, predictably, distort program design." (BCOAPO Argument, p. 13) (emphasis in original)

In its Reply, Terasen notes that "BCOAPO and BCSEA-SCBC have made submissions on attribution of benefits. This issue is not relevant to the assessment of the proposed portfolio, as the assessment does not include any attribution of benefits. With respect to the assessment of future portfolios, the Terasen Utilities repeat and rely on the submissions made in paragraphs 109 to 111 of the Initial Submissions" (which argue for the inclusion of attribution savings.)
(Terasen Reply, p. 20)

Commission Determination

The Commission Panel notes Terasen's comment that the attribution issue is not relevant to this Application as the assessment does not include any attribution of benefits. However, as in the case of free riders, the Commission Panel does consider that this issue is likely to become a factor as the DSM initiatives of Terasen become more fully developed and refined, and therefore should be addressed in this Decision.

The Commission Panel accepts the position of BC Hydro that attribution of savings from codes and standards should be evaluated on a case-by-case basis and that the attribution rate should reflect the level of support for market transformation. The Commission Panel shares the BCSEA-SCBC's concern, as detailed in Mr. Plunkett's evidence, that the attribution concept can distort program design.

The Commission Panel rejects the Attribution to Regulatory Change proposal made in the Application and refers this issue back to Terasen to redesign and resubmit with its next annual EEC report to the Commission, giving consideration to a modified version of the Application's attribution proposal reflecting the provisions of the DSM Regulation which come into effect for Terasen on June 1, 2009. The Commission Panel directs Terasen to address, in the modified version, the matters raised by BC Hydro and BCSEA-SCBC, and also to give consideration to factors such as the length of time a particular program element has been operative at the time any applicable regulation is introduced and how compatible the program initiative is with the new regulation (e.g. if a regulation is introduced with a higher or lower threshold or standard than the program design).

3.4 Carbon Pricing

As part of the Application, Terasen seeks an order approving certain changes to the benefit-cost analysis undertaken in respect of EEC expenditures, including recognizing the impact of carbon pricing as one of the inputs to the benefit-cost tests. (Exhibit B-1, pp. 15-16)

Terasen proposes that additional customer bill savings from the implementation of the tax should be included in the benefit-cost analysis for EEC programs. Terasen proposes that the activities supported by the EEC Application will contribute to consumer education and provide consumers with tools to help them reduce the impact of the proposed carbon tax on their energy expenditures. (Exhibit B-1, p. 41)

Terasen summarises its position with respect to the carbon tax matter in Argument as follows: "The customers will also enjoy a benefit associated with reduced Carbon Tax costs. Customers that install an efficient appliance or design a more efficient building as a result of Terasen's EEC initiatives will use less gas, and will therefore pay less Carbon Tax. Therefore, the avoided Carbon

Tax was included in the participant benefits, as noted in Appendices 11A and 11B of the Application" [Terasen Argument, p. 21)

Commission Determination

The Commission Panel accepts Terasen's proposal for the carbon tax reduction as an appropriate factor to be included in computing the EEC cost-benefit analysis.

3.5 Accountability Mechanisms

Terasen summarises its proposal for accountability mechanisms as follows:

> "In this Application the Companies have recognized the need for accountability for the funds approved for EEC programs. First, any funds not spent will not be charged to the regulatory asset deferral account. Second, the Companies intend to monitor the portfolio TRC on a monthly basis, and have proposed to file an Annual EEC Report with the Commission by the end of the first quarter every year. The Report will detail program activity, expenditures, and cost-benefit results for the previous year, as well as describe program activity and provide forecasts for the upcoming year. Third, in the event that the relief sought is granted, the Companies would form and engage an EEC stakeholder group with membership representing a broad cross section of stakeholders identified in the Application. Fourth, the Companies have indicated their intention to hold annual EEC workshops with stakeholders, at which the Companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs. Fifth, the Companies are proposing to develop many of the programs for the commercial sector and the DSM for Affordable Housing sector in conjunction with stakeholder advisory groups." (Terasen Argument, p. 39)

<u>Intervenor Positions</u>

BCSEA-BCSC states that they: ". . . support this [funding] approach, noting that the proposed accountability mechanisms are designed to be more effective and efficient than having on-going Commission involvement in decision-making within the portfolio during the Funding Period" and "BCSEA-SCBC acknowledge and support the additional accountability mechanisms proposed by Terasen in [Terasen Argument] paragraph 112." (BCSEA-SCBC Argument, pp. 5, 20)

BCOAPO argues that, should the Application be approved, an independent audit process should be required with respect particularly to free ridership, attribution and redirection of funds. (BCOAPO Argument, p. 14)

Commission Determination

The Commission Panel accepts Terasen's accountability undertakings, and considers that, while the proposal to evaluate the EEC project using the TRC test at the Portfolio level has been accepted, TRC calculations for each program area, initiative and measure should also be included in the accountability reporting as a means of assessing the components of the Project and their ongoing effectiveness.

Commission Panel directs that the annual EEC Report include the following:

- TRC, RIM, UC, and Participant test calculations of DSM at the Program Area initiative and individual measure levels in addition to the total Portfolio level reporting. Reporting of the Residential & Commercial EE program areas should also be made at the New Construction and Retrofit levels.
- any inter and intra Program Area initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives, and measures as the case may be.
- data for fuel switching programs should be tracked in a manner which allows for reporting types of fuels replaced by natural gas, including estimated GHG impacts.

The Commission Panel also directs Terasen to include in its annual EEC Report to the Commission a discussion of its internal data gathering, monitoring and reporting control processes. The discussion should include a description of how these processes ensure that funds expended and the statistical results of the programs implemented are completely and accurately recorded and monitored, including any related internal check and audit processes. The report should also discuss how Terasen has measured or estimated the results of the EEC expenditure initiatives.

4.0 CAPITALISATION OF INCREMENTAL EEC EXPENDITURES

Terasen's proposed EEC expenditures are summarised and discussed in Section 2.0. Terasen proposes to capitalise the approved incremental expenditures as a regulatory deferral account in the year in which the expenditures are incurred, with amortisation over 20 years commencing the year after the expenditures are made. The proposed amortisation period is addressed in Section 5.0 of this Decision.

Terasen's total EEC expenditures for 2008 to 2010 include operating and maintenance (O&M) expenditures for its previously approved DSM programs for 2008 and 2009. Terasen proposes to charge those O&M costs to operations in those years, with the balance of the total EEC expenditures being added to a new EEC deferral account. This method accounts for the impact of the legacy DSM Operating & Maintenance expenditures having been considered in the PBR and RR Extended Settlements for TGI and TGVI respectively. The reconciliation of the Total EEC expenditures and the amounts expensed and deferred is illustrated in the following table.

Table 7

Deferral Reconciliation	TGI			TGVI		
	2008	2009	2010	2008	2009	2010
Total EEC Expenditures	13,996	15,752	17,196	2,830	3,043	3,793
Expensed per Extended Settlements	1,624	1,624	-	500	500	-
Proposed Deferral Addition	12,372	14,128	17,196	2,330	2,543	3,793

Source: Exhibit B-1, pp. 49, 95, 97

Terasen points out that its proposed accounting treatment to capitalize the EEC expenditures is permitted under current Canadian Institute of Chartered Accountants (CICA) accounting standards. Terasen also notes that, effective 2011, all publicly accountable entities, including it will be required to comply with International Financial Reporting Standards (IFRS). Terasen is of the view that: "... the proposed financial treatment of EEC funding also meets the requirements of IFRS" and goes on to state that "[i]f, however, after further discussion and closer examination in conjunction with auditors and other utilities, the EEC funding failed to pass these [IFRS] tests, then [Terasen] will revisit the program to ensure that it continues in a fashion which maintains an alignment on interests between customers, investors and government policy." (Exhibit B-1, pp. 81-82)

Intervenor Positions

BCSEA-SCBC comments on Terasen's "... proposal to capitalize incremental EEC expenditures amortised over 20 years. BCSEA-SCBC supports this concept, including the 20 year amortisation period due to the life-expectancy of gas DSM measures." (BCSEA-SCBC Argument, p. 17)

Commission Determination

The Commission Panel accepts Terasen's proposal to capitalize the approved EEC expenditure to a regulatory deferral account, and to amortitse the deferral account balances over an appropriate time period. The related issues of the quantum of the expenditures approved and the appropriate amortisation period(s) for the program areas are addressed in other sections of this Decision.

5.0 AMORTISATION OF EEC EXPENDITURES

Terasen proposes to amortise its EEC expenditures, including both program, and incentive and rebate costs, over a 20 year period, based on a calculation of the 22.5 years as the weighted average measurable life of the proposed appliance and energy system installations. Terasen's weighted average calculation is based on achieving estimated volumes, mix and lives of installations for the various measures being proposed. (Exhibit B-1, p. 80, and Appendix 40.2) FortisBC and BC Hydro each use 10 year amortisation periods. (Exhibit B-2, p. 95) Terasen states: "…research failed to uncover any examples where utilities are using or proposing amortisation periods as long as 20 years" for DSM programs. (Exhibit B-2, p. 97)

Commission Determination

The Commission Panel rejects the 20 year amortisation period proposed by Terasen. The Commission panel considers the underlying forecast assumptions on which the Terasen methodology is based to be inherently uncertain, and deserving little weight. The Commission Panel does consider that a ten year amortisation period provides a reasonable balance, considering both the DSM objectives and customer impact. Terasen is directed to base its amortisation of approved EEC expenditures over periods not to exceed 10 years.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2009.

A.W. KEITH ANDERSON
COMMISSIONER

ALISON A. RHODES
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-36-09

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
Energy Efficiency and Conservation Programs Application

BEFORE: A.W.K. Anderson, Commissioner April 16, 2009
A.A. Rhodes, Commissioner

O R D E R

WHEREAS:

A. On May 28, 2008 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively "Terasen") filed an application for approval of various concepts and expenditures in support of an expanded energy efficiency and conservation ("EEC") strategy, and to capitalize incremental EEC expenditures by charging the expenditures to a regulatory asset deferral account and amortising the balance over 20 years (the "Application"); and

B. On June 3, 2008 the British Columbia Utilities Commission ("Commission") issued a letter requesting that interested parties register and file comments on Terasen's proposed timetable before June 11, 2008; and

C. By Order G-102-08 dated June 19, 2008, the Commission issued a Preliminary Regulatory Timetable which included two rounds of Commission Information Requests and one round of Intervenor Information Requests, and requested comments from all parties on further process for reviewing the Application; and

D. In response to Order G-102-08, the Commission received replies from Terasen and the following Intervenors: B.C. Ministry of Energy Mines and Petroleum Resources ("MEMPR"), British Columbia Hydro and Power Authority ("BC Hydro"), B.C. Sustainable Energy Association and the Sierra Club of British Columbia ("BCSEA-SCBC"), the Commercial Energy Consumers Association of British Columbia ("CEC"), B.C. Old Age Pensioners' Organization et al. ("BCOAPO"); and

E. Following its review of comments from Terasen and Intervenors, the Commission issued Letter L-39-08 dated September 8, 2008 ordering a second round of Intervenor Information Requests; and

F. By Order G-130-08 dated September 18, 2008 the Commission established a Written Hearing Process and Regulatory Timetable for its review of the Application; and

G. The Written Hearing Process concluded on December 5, 2008 with the filing of Terasen's reply submission; and

H. The Commission has reviewed and considered the evidence and submissions of Terasen and Registered Intervenors.

NOW THEREFORE pursuant to section 44.2 of the Utilities Commission Act, and subject to the specific determinations, qualifications and directions set out in the Decision issued concurrently with this Order, the Commission orders as follows:

1. The following proposed expenditures are accepted:

   (a) $31.077 million for the combined Residential Energy Efficiency and Commercial Energy Efficiency programs;

   (b) Expenditures for programs or initiatives directed at fuel switching away from fossil fuels with a higher carbon content than that of natural gas to natural gas;

   (c) $6.918 million for the Conservation Education and Outreach program;

   (d) $3 million for Joint Initiatives; and

   (e) $0.5 million for Conservation Potential Review.

2. Expenditures in the sum of $3 million for Innovative Technologies, Natural Gas Vehicles and Measurement and $1.5 million for Trade Relations are rejected.

3. The proposed portfolio approach is accepted.

4. The Total Resource Cost test is accepted as the appropriate test for cost effectiveness.

5. The proposal to exclude the free rider factor from benefit-cost analyses is rejected.

6. The proposal for Attribution of Regulatory Changes is rejected.

7. The proposal to include carbon tax reductions in computing benefit-cost analyses is accepted.

8. Terasen is to commence the planning process for development of an Industrial EEC program and file a report with the Commission within 90 days of the date of the Decision.

9. The proposal for accountability mechanisms is accepted and Terasen is to file an annual report on its EEC activities as described in the Commission's Decision.

10. Subject to paragraph 11 below, the proposal to capitalise the approved EEC expenditure to a regulatory deferral account and to amortise the deferral account balances is accepted.

11. The proposal to amortise EEC expenditures over a 20 year period is rejected. Terasen is directed to base its amortisation of approved EEC expenditures over periods not to exceed 10 years.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of April 2009.

BY ORDER

A.W.K. Anderson
Commissioner

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
Energy Efficiency and Conservation Programs Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated June 3, 2008 issuing request for comments on process and proposed timetable
A-2	Letter dated June 19, 2008 issuing Order No. G-102-08 establishing the Regulatory Timetable
A-3	Letter dated June 20, 2008 issuing Commission Information Request No. 1
A-4	Letter dated July 25, 2008 issuing Commission Information Request No. 2
A-5	Letter dated September 8, 2008 establishing a Second Round of Information Requests
A-6	Letter dated September 12, 2008 issuing Commission Information Request No. 3
A-7	Letter dated September 18, 2008 and Order No. G-130-08 establishing a Written Hearing and Regulatory Timetable
A-8	Letter dated October 22, 2008 issuing Information Request #1 to BC Hydro
A-9	Letter dated October 24, 2008 filing Information Request No. 1 to BCSEA
APPLICANT DOCUMENTS	
B-1	Letter dated May 28, 2008 filing Energy Efficiency and Conservation Programs Application
B-2	Letter dated July 11, 2008 filing response to the Commission's Information Request No. 1

Exhibit No.	Description
B-2-1	**CONFIDENTIAL** - Letter dated July 11, 2008 filing response to the Commission's Information Request No. 1, Questions 9.2 and 22.1
B-3	Letter dated August 15, 2008 filing response to the Commission's Information Request No. 2
B-4	**CONFIDENTIAL** - Letter dated August 15, 2008 filing response to the Commission's Information Request No. 2
B-5	Letter dated August 15, 2008 filing response to BC Hydro's Information Request No. 1
B-6	Letter dated August 15, 2008 filing response to BCOAPO's Information Request No. 1
B-7	Letter dated August 15, 2008 filing response to BC Sustainable Energy Assoc & Sierra Club of Canada Information Request No. 1
B-8	Letter dated August 15, 2008 filing response to the Commercial Energy Consumers Association of BC's Information Request No. 1
B-9	Letter dated August 15, 2008 filing response to the Ministry of Energy, Mines & Petroleum Resources' Information Request No. 1
B-10	Letter dated August 15, 2008 filing response to the Rental Owners & Managers Society of BC's Information Request No. 1
B-11	Letter dated August 27, 2008 filing comments on submissions from Intervenor and on the further procedural process
B-12	**WITHDRAWAL ORIGINAL B-11, AMENDED AND REPOSTED** - Letter dated October 6, 2008 filing response to the Commission's Information Request No. 3
B-13	**WITHDRAWAL ORIGINAL B-12, AMENDED AND REPOSTED -** Letter dated October 6, 2008 filing response to the BCOAPO's Information Request No. 2
B-14	**WITHDRAWAL ORIGINAL B-13, AMENDED AND REPOSTED -** Letter dated October 6, 2008 filing response to the BCSEA's Information Request No. 2
B-15	Letter dated October 24, 2008 issuing Information Request No. 1 to BC Hydro and Power Authority
B-16	Letter dated October 24, 2008 issuing Information Request No. 1 to BCSEA and SCBC

Exhibit No.	Description

INTERVENOR DOCUMENTS

C1-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR) –** Letter dated June 10, 2008 from Duane Chapman, Senior Regulatory Advisor, requesting participation in the proceedings
C1-2	Letter dated July 24, 2008 filing MEMPR's Information Request No. 1
C1-3	Letter dated August 27, 2008 filing comments on further procedural process
C1-4	Letter dated October 24, 2008 filing comment for consideration
C2-1	**BRITISH COLUMBIA HYDRO & POWER AUTHORITY (BC HYDRO) –** Online web registration received June 10, 2008 filing request for Intervenor status
C2-2	Letter dated June 11, 2008 filing comments on the regulatory review process and timetable
C2-3	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C2-4	Letter dated August 27, 2008 filing comments on further procedural process
C2-5	Letter dated September, 2008 filing request for an extension for filing Intervenor Evidence
C2-6	Letter dated October 14, 2008 filing BC Hydro's Evidence
C2-7	Letter dated November 7, 2008 filing responses to the Commission's and Terasen Utilities' Information Request No. 1
C3-1	**RENTAL OWNERS AND MANAGERS SOCIETY OF BC (ROMS) –** Letter dated June 10, 2008 from Al Kemp, CEO, requesting Intervenor status
C3-2	Letter dated July 21, 2008 filing Information Request No. 1 to Terasen
C4-1	**BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION (BCOAPO)** - Letter dated June 11, 2008 request for Registered Intervenor status for Leigha Worth, Eugene Kung, and James Wightman of Econalysis Consulting
C4-2	Letter dated June 11, 2008 filing comments on procedural matters

Exhibit No.	**Description**
C4-3	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C4-4	Letter dated August 27, 2008 filing comments on further procedural process
C4-5	Letter dated September 15, 2008 filing Information Request No. 2 to Terasen
C5-1	**BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA) AND THE SIERRA CLUB OF CANADA (BRITISH COLUMBIA CHAPTER) (SCCBC)** - Letter dated June 11, 2008 request for Registered Intervenor status
C5-2	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C5-3	Letter dated August 27, 2008 from William J. Andrews, legal counsel, filing comments on further procedural process
C5-4	Letter dated September 15, 2008 filing Information Request No. 2 to Terasen
C5-5	Letter dated October 14, 2008 filing BCSEA et al Evidence
C5-6	Letter dated October 16, 2008 filing Errata to Evidence (Exhibit C5-5)
C5-7	Letter dated November 7, 2008 filing response to the Commission's Information Request
C5-8	Letter dated November 7, 2008 filing response to Terasen's Information Request with worksheet
C6-1	**FORTISBC INC.** - Letter dated June 12, 2008 from Joyce Martin, filing request for Registered Intervenor status
C7-1	**PACIFIC NORTHERN GAS LTD. (PNG) –** Online web registration received June 18, 2008 from Craig Donohue filing request for Intervenor status
C8-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CECBC)** - Letter dated June 18, 2008 from Christopher Weafer, Owen Bird, legal counsel, filing request for Registered Intervenor status and comments
C8-2	Letter dated July 25, 2008 filing Information Request No. 1 to Terasen
C8-3	Letter dated August 27, 2008 from Christopher Weafer, Owen Bird, legal counsel, filing comments on further procedural process

Exhibit No.	Description
C9-1	**DIRECT ENERGY MARKETING LIMITED (DEML)** - Online web registration dated June 25, 2008 from Chad Painchaud, filing request for Registered Intervenor status
LETTERS OF COMMENT	
E-1	**CANADIAN MORTGAGE AND HOUSING CORPORATION (CMHC – SCHL)** - Letter of Comment dated June 16, 2008, faxed from Lance Jakubec, Senior Research Consultant, in support of the application
E-2	**CITY GREEN SOLUTIONS** – Letter of Comment received June 17, 2008 from Peter Sundberg, Executive Director
E-3	**LIGHT HOUSE SUSTAINABLE BUILDING CENTRE** - Letter of Comment received June 17, 2008 from Helen Goodland
E-4	**CANADIAN HOME BUILDERS' ASSOCIATION (VICTORIA) (CHBA)**- Letter of Comment received June 18, 2008 from Casey Edge, Executive Officer
E-5	**HEARTH, PATIO & BARBECUE ASSOCIATION OF CANADA (HPBAC)** - Letter of Comment received June 18, 2008 from Tony Gottschalk, Manager
E-6	**FRASER BASIN COUNCIL** – Letter of Comment received June 20, 2008 from Bob Purdy, Director, Corporate Development & Communications
E-7	**PACIFIC RESOURCE CONSERVATION SOCIETY** – Letter of Comment received June 24, 2008 from Darla Simpson, Executive Director
E-8	**CANADIAN HOME BUILDERS' ASSOCIATION (KAMLOOPS) (CHBA)** - Letter of Comment dated June 25, 2008 from Patsy Bourassa, Executive Officer
E-9	**URBAN DEVELOPMENT INSTITUTE – PACIFIC REGION (UDI) -** Letter of Comment dated July 3, 2008 from Jeff Fisher, Deputy Executive Director
E-10	**FRASER VALLEY HOME BUILDERS ASSOCIATION (FVHBA) -** Letter of Comment dated July 8, 2008 from Jan Field, Executive Officer
E-11	**CANADIAN MANUFACTURERS & EXPORTERS – BC DIVISION -** Letter of Comment dated July 5, 2008 from Craig Williams, Vice President
E-12	**NATURAL RESOURCES CANADA -** Letter of Comment dated July 9, 2008 from John Cockburn, Director, Office of Energy Efficiency

Exhibit No.	Description
E-13	**CANADIAN HOME BUILDERS ASSOCIATION OF BC (CHBA BC) -** Letter of Comment dated July 8, 2008 from M.J. Whitemarch, Chief Executive Officer
E-14	**CITY OF NANAIMO -** Letter of Comment dated July 10, 2008 from Gary Korpan, Mayor
E-15	**CITY OF VICTORIA -** Letter of Comment dated July 15, 2008 from Alan Lowe, Mayor
E-16	**CITY OF LANGFORD -** Letter of Comment dated July 22, 2008 from Rob Buchan, Clerk-Administrator
E-17	**TOWN OF LADYSMITH –** Letter of Comment dated July 24, 2008 from Mayor Robert Hutchins
E-18	**CORPORATION OF THE VILLAGE OF CUMBERLAND -** Letter of Comment dated July 18, 2008 from Christine Makarowski, Corporate Services Manager
E-19	**THE CORPORATION OF THE CITY OF NORTH VANCOUVER -** Letter of Comment dated July 29, 2008 from Darrell Mussatto, Mayor
E-20	**THE CORPORATION OF THE DISTRICT OF WEST VANCOUVER -** Letter of Comment dated July 30, 2008 from Clay Nelson, Manager
E-21	**BROOK + ASSOCIATES INC. -** Letter of Comment dated July 2, 2008 from Blair Chisholm, Planning Manager
E-22	**CITY OF POWELL RIVER -** Letter of Comment dated July 30, 2008 from Mair Claxton, City Clerk
E-23	**CORPORATION OF DELTA -** Letter of Comment dated July 30, 2008 from Lois E. Jackson, Mayor
E-24	**BC CHAMBER OF COMMERCE -** Letter of Comment dated August 11, 2008 from John R. Winter, President & CEO
E-25	**CANADIAN GAS ASSOCIATION -** Letter of Comment dated August 14, 2008 from Michael Cleland, President & CEO
E-26	**CITY OF SURREY -** Letter of Comment dated August 11, 2008 from Dianne L. Watts, Mayor
E-27	**BUSINESS COUNCIL OF BRITISH COLUMBIA -** Letter of Comment dated August 15, 2008 from Virginia Greene, President & CEO

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-140-09

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and
Revenue Deficiency Deferral Account Balance as at December 31, 2008

BEFORE:

A.W.K. Anderson, Panel Chair/Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

November 26, 2009

O R D E R

WHEREAS:

A. On June 29, 2009, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed an application for approval of interim and permanent delivery rates effective January 1, 2010 (the "Application") pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the "Act") and section 2.1 of the Special Direction to the British Columbia Utilities Commission ("Commission") issued pursuant to Order in Council 1510 ("Special Direction"), requesting (a) no change in 2009 sales service rates and (b) a reduction in rates for firm transportation service, other than for those customers who have specified rates in their transportation service agreements, in the amount of 4.75 percent; and

B. TGVI proposed that the rates established for 2010 should also remain in place for 2011; and

C. TGVI also applied pursuant to sections 59 to 61 of the Act and section 2.10(a)(i) of the Special Direction for interim and permanent approval of TGVI's forecast cost of service for 2010 and 2011, subject to the need to recover any Accumulated Revenue Deficiency in the Revenue Deficiency Deferral Account after December 31, 2009 and any changes in TGVI's return on equity; and

D. TGVI also applied pursuant to section 2.10(f) of the Special Direction for approval of the December 31, 2008 year-end balance in the Revenue Deficiency Deferral Account in the amount of $7,149,210, and for approval of other items identified in the Special Direction; and

E. TGVI sought other approvals in the Application, including orders pursuant to sections 59 to 61 of the Act, approving Tariff changes effective January 1, 2010 for Compression and Refueling and Transportation Services for Natural Gas Vehicles, and economic models for evaluating biogas projects and alternative energy extensions for geo-exchange, solar thermal and district energy systems to complement its core natural gas business; and

F. TGVI proposed a written hearing process to address the Application but was open to a negotiated settlement process ("NSP"); and

G. On July 2, 2009, the Commission Panel issued Order G-84-09, which provided for a Workshop on July 13, 2009 and a first Procedural Conference on July 15, 2009 to hear submissions on the appropriate regulatory process and TGVI's proposed preliminary regulatory timetable attached to that order; and

H. In accordance with Order G-84-09, TGVI held a Workshop to review the Application on Monday, July 13, 2009; and

I. Procedural Conference No. 1 was held on Wednesday, July 15, 2009 at which the Commission Panel heard submissions regarding the Application process and inclusion of Alternative Energy Solution proposals within the process; and

J. The Commission Panel considered the Submissions received at Procedural Conference No. 1, and concluded that a Regulatory Timetable establishing a second Procedural Conference following TGVI's responses to the second round of Information Requests was required. It was also determined that proposed Alternative Energy Solutions included in TGVI's Applications would be reviewed as part of the Revenue Requirements proceedings, that information requests consistent with TGI would be cross referenced to those requests, and that interim rates and the Revenue Surplus Deferral Account were not approved at that time and would be reviewed at the second procedural conference; and

K. Procedural Conference No. 2 was held on Friday, September 25, 2009 at which the Commission Panel heard further submissions regarding the process of the Application, location of the proceedings and other matters that would assist the Commission's efficient review of the Application. Primary issues raised were whether a separate Certificate of Public Convenience and Necessity ("CPCN") review was required for the Alternative Energy Solutions proposed in the Application and whether the regulatory process should be in the form of an oral or written hearing or NSP; and

L. Intervenors did not request a separate CPCN process for the Alternative Energy Solutions and all Intervenors supported an NSP for the review of the Application. The Interveners submitted that in the event the NSP does not successfully resolve all issues, an Oral Public Hearing should be subsequently ordered by the Commission Panel. TGVI requested that if an Oral Public Hearing is established that it be limited in scope; and

M. TGVI proposed a delay in its application for interim rate approval until the end of November. If a Commission decision has been issued on the Terasen Gas allowed return on equity and capital structure and this Application (the "Applications") by the end of November, then it will apply for approval of permanent rates effective January 1, 2010. If a Commission decision has not been issued on the Applications by the end of November, then TGVI will apply for interim rates effective January 1, 2010; and

N. By Order G-120-09 the Commission Panel established a negotiated settlement process for the review of the Application commencing on October 29, 2009; and

O. On November 13, 2009, the Negotiated Settlement Agreement ("NSA"), together with the Letters of Support received from the participants in the NSP ("Settlement Package"), was made public and circulated to the Commission Panel; and

P. The Settlement Package was also distributed to Registered Intervenors who did not participate in the NSP ("Other Intervenors"). The Other Intervenors were requested to provide their comments on the Settlement Package to the Commission by November 20, 2009. The Commission Panel received no comments from Other Intervenors regarding the Settlement Package; and

Q. The Commission Panel, having reviewed the proposed NSA and the comments related thereto and noting the support of all parties to the Proposed Settlement, in which only sections 7.1 (a) and (b) are severable, subject to the provisions of section 7.2, considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the Act and the Special Direction issued pursuant to Order in Council 1510 the Commission orders as follows:

1. The Negotiated Settlement Agreement attached as Appendix A to this Order is approved.

2. TGVI is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. The Commission will accept, subject to timely filing by TGVI, amended permanent Gas Tariff Rate Schedules in accordance with the terms of this Order. TGVI is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of November 2009.

BY ORDER

Original signed by:

A.W.K. Anderson
Panel Chair/Commissioner

Attachment

ERICA HAMILTON
COMMISSION SECRETARY
Commission. Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 29924

VIA EMAIL

November 13, 2009

Registered Intervenors
(*TGVI-2010-11RR-RI*)

Dear Registered Intervenors:

Re: Terasen Gas (Vancouver Island) Inc.
2010-2011 Revenue Requirements and Rate Design Application
Negotiated Settlement

Enclosed with this letter is the proposed settlement package for Terasen Gas (Vancouver Island) Inc.'s 2010-2011 Revenue Requirements and Rate Design Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 20, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

N. Lapierre
for: Erica M. Hamilton

PWN/yl
Attachments
cc: Mr. Tom Loski
Chief Regulatory Officer
Terasen Gas Inc.
(Via Email: *regulatory.affairs@terasengas.com*)

Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

November 13, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Philip Nakoneshny, Director, Rates and Finance

Dear Mr. Nakoneshny:

Re: Terasen Gas (Vancouver Island) Inc. ("TGVI")
2010 and 2011 Revenue Requirements and Rate Design Application
Negotiated Settlement Agreement

On June 29, 2009, TGVI filed its 2010 and 2011 Revenue Requirements Application, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 which was amended by filings on July 23 and September 22, 2009 (the "Application").

In accordance with Commission Order No. G-84-09 issued on July 2, 2009, a Workshop was held on July 13, 2009 for a review of the Application, a Procedural Conference was held on July 15, 2009, and TGVI responded to two rounds of Information Requests. In accordance with Commission Order No. G-90-09 issued on July 20, 2009, a second Procedural Conference was held on September 25, 2009 and on October 2, 2009, the Commission issued Order G-120-09 establishing a Negotiated Settlement Process ("NSP") for the Application. In accordance with Order No. G-120-09, the NSP commenced on Tuesday, November 3, 2009 and concluded on Thursday, November 5, 2009.

TGVI has reviewed the attached settlement documents, including the Negotiated Settlement Agreement and associated financial schedules (collectively the "Negotiated Settlement") arising from the NSP. TGVI recognizes the Negotiated Settlement as being the product of good faith compromises among parties with diverse interests of the issues raised by the Application. In fulfilling their role pursuant to the Commissions NSP Guidelines, Commission Staff made additional information available to the parties which they believed was in the public interest. The parties considered all such information in reaching the compromise Settlement Agreement and Terasen Gas considers the resulting Negotiated Settlement to be fair, just and reasonable. As the Negotiated Settlement represents compromises among the parties and an overall balance of interests, TGVI stresses that the Negotiated Settlement should be considered as a package, with no part being severed unless otherwise stated in the Agreement. On that basis, TGVI accepts the Negotiated Settlement.

TGVI would like to express sincere thanks to Commission Staff and Intervenor representatives for their active participation in achieving this Negotiated Settlement Agreement on the Application. TGVI also wishes to thank the NSP facilitator, Mr. Paul Cassidy, for his leadership, guidance and assistance to all parties throughout the NSP process.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Tom A. Loski

Attachment

cc (e-mail only): Parties to the NSP

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas (Vancouver Island) Inc.
for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008
Negotiated Settlement Process

WHEREAS:

A. On June 29, 2009, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed its 2010 and 2011 Revenue Requirements Application, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008 which was amended by filings on July 23 and September 22, 2009 (the "Application"); and

B. Amongst other things, the Application sought:

1. An order pursuant to sections 59 to 61 of the *Utilities Commission Act* (the "Act"), section 2.1 of the Vancouver Island Natural Gas Pipeline Special Direction ("Special Direction"), approving permanent rates for Core Market customers, effective January 1, 2010. As set out in Part III, Section B, Tab 3 of the Application, compared to 2009 rates, the service rates for which TGVI seeks approval are the same as 2009 sales service rates; and

2. An order pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction, approving permanent rates for transportation customers, other than those transportation customers who have specified rates in their transportation service agreements. As set out in Part III, Section B, Tab 3 of the Application, the rates for which TGVI seeks approval are:

   a. A reduction in rates for firm transportation service in the amount of 5.18% (as compared to 2009), effective January 1, 2010; and

   b. A reduction in rates for summer interruptible transportation service in the amount of 5.18% (as compared to 2009), effective January 1, 2010; and

   c. Winter interruptible rates of $1.384/GJ effective January 1, 2010 and of $1.401/GJ effective January 1, 2011; and

3. These rates are subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity as described in Part III, Section C, Tab 10; and

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

4. An order pursuant to section 2.10(a)(i) of the Special Direction approving TGVI's forecast Cost of Service for 2010 and 2011, as set out in Part III, Section C, Tab 2 of the Application, but subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity as described in Part III, Section C, Tab 10; and

5. An order pursuant to sections 59 to 61 of the Act approving the schedule of demand and commodity charges as set out in Schedule A of Tariff Supplement No. 4 (Storage and Delivery Agreement between TGI and TGVI), as set out in Part III, Section B, Tab 3 of the Application.

6. An order pursuant to sections 59 to 61 of the Act approving the creation of the Rate Stabilization Deferral Account ("RSDA"), effective January 1, 2010, for the purposes of capturing any annual revenue surplus in 2010 and 2011, with any balance at the end of 2011 to be returned to Core Market customers beginning January 1, 2012 in the manner described in Part III, Section D, Tab 1.

7. An order pursuant to sections 59 to 61 of the Act approving the creation of the 2009 Revenue Surplus Account for the purposes of capturing any 2009 revenue surplus in excess of the amount needed to eliminate the debit balance in the RDDA, and its proposed allocation to customers and amortization as set out in Part III, Section D, Tab 1 of the Application.

8. An order pursuant to section 2.10(a)(i) of the Special Direction approving its forecast capital expenditures for 2010 and 2011, as set out in Part III, Section C, Tab 9 of the Application.

9. An order pursuant to section 2.10(a)(ii) of the Special Direction approving its forecast Revenue for 2010 and 2011, based on its proposed rates, as set out in Part III, Section D, Tab 1 of the Application.

10. An order approving the forecast gross O&M expenditures for the forecast period 2010 and 2011, as determined through and supported by Part III, Section C, Tab 6 of the Application of $32,104,700 and $33,650,000 respectively, and to fix those amounts for the purposes of determination of RDDA and/or RSDA balances at the end of each year.

11. An order pursuant to section 2.10 (f) of the Special Direction approving the December 31, 2008 year end balance in the RDDA of $7,149,210, as set out in Part III, Section B, Tab 2 of the Application.

12. An order pursuant to section 44.2 of the Act approving an expenditure schedule for the continuation in 2011 of TGVI's residential and commercial Energy Efficiency and Conservation ("EEC") funding, as well as new EEC funding for 2010 and 2011 for innovative technologies; and

13. New tariff offerings and economic tests for Compression and Refuelling and Transportation Services for Natural Gas Vehicles ("NGV"), geo-exchange, solar thermal and district energy systems and a pilot program for Biogas; and

C. A complete listing of the relief sought by TGVI in the Application was included in Section E (pages 436-443)[1] of the Application; and

D. In accordance with Commission Order No. G-84-09 issued on July 2, 2009, a Workshop was held on July 13, 2009 for a review of the Application, a procedural conference was held on July 15, 2009, and TGVI responded to two rounds of Information Requests; and

E. In accordance with Commission Order No. G-90-09 issued on July 20, 2009, a second procedural conference was held on September 25, 2009; and

F. On October 2, 2009, the Commission issued Order G-120-09 establishing a Negotiated Settlement Process (“NSP”) for the Application; and

G. The Parties to the NSP were TGVI, British Columbia Old Age Pensioners et al. (“BCOAPO”), Commercial Energy Consumers Association of British Columbia (“CEC”) and British Columbia Hydro and Power Authority (“BC Hydro”) (collectively referred to in this Agreement as the “Parties”); and

H. At the outset of the NSP on November 3, 2009, Commission Staff provided the Parties with a document prepared by the Commission Panel titled “Issues of Particular Concern to the Commission Panel”, a copy of which is appended as Appendix 1 to this Agreement; and

I. The NSP was held on November 3-5, 2009; and

J. The Parties have negotiated in good faith to achieve a compromise settlement, reflected in this Agreement, of the issues raised by the Application, and further consider the Agreement reached to be fair, just and reasonable; and

K. This Agreement consists of four sections:

Part I includes general provisions;

Part II includes the items agreed to that differ from what was requested in the Application;

Part III includes the items agreed to that remain as proposed by TGVI in the Application; and

Part IV includes revised financial schedules reflecting all items set out in the Agreement.

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[1] Pages 436 and 437 of the Application were amended on July 23, 2009 and pages 438 to 443 were amended on September 22, 2009.

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS

PART I – GENERAL

1. Agreement a Product of Compromise

The Parties recognize and emphasize that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agree that any compromises resulting from this Agreement are without prejudice to the Parties' ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

2. Whole Agreement

The Parties agree that, unless otherwise stated in this Agreement, portions of this Agreement cannot be removed or changed by the Commission without nullifying the whole Agreement.

3. TGVI to Manage Business

The Parties agree that TGVI will have the discretion to manage its business and determine how best to allocate the overall O&M and Capital expenditures stipulated in this Agreement.

4. Final IFRS Rate-regulated Activity Standard

The Parties acknowledge that this Agreement is predicated on the Final IFRS Rate-regulated Activity Standard permitting the financial accounting treatment contemplated in this Agreement in the manner outlined in the current Exposure Draft on Rate-regulated Activities. The Parties agree that if, in TGVI's opinion, the Final IFRS Rate-regulated Activity Standard differs from the current Exposure Draft on Rate-regulated Activities so as not to permit the financial accounting treatment contemplated in this Negotiated Settlement Agreement, which among other things anticipates the recognition of regulatory assets and liabilities for external reporting purposes, then TGVI is at liberty to apply to the Commission during the period of this Agreement for a determination of that issue, and to seek changes in the regulatory treatment contemplated in this Agreement to accord with the Final IFRS Rate-regulated Activity Standard, with the resulting impacts flowed through into rates commencing in 2011.

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TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

PART II – AGREED CHANGES FROM THE APPLICATION

5. Use Per Customer Rates

The Parties agree that the use per customer rates will be as set out in the Application.

6. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGVI for 2010:

(a) TGVI will reallocate from residential and commercial EEC programs an additional $0.4 million from the amount approved for 2010 in the EEC Decision[2] to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2010 (currently at $0.2 million).

(b) EEC funding for innovative technologies will be $0.478 million for 2010, which is the amount requested by TGVI in the Application.

(c) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

7. EEC Funding for 2011

7.1 The Parties agree as follows in respect of the EEC funding sought by TGVI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $4.726 million, which is the amount requested by TGVI in the Application.

(b) TGVI will reallocate from 2011 residential and commercial EEC funding ($4.726 million for 2011) an additional $0.4 million to low income and rental housing programs. This brings the total for low income and rental housing programs to $0.6 million for 2011.

(c) EEC funding for innovative technologies will be $0.956 million for 2011, which is the amount requested by TGVI in the Application.

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[2] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application.

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TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 438, Item 15). However, Innovative Technology programs will be managed by TGVI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGVI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(e) TGVI will report to the Commission on innovative technology programs as part of TGVI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $4.726 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGVI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGVI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGVI's EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGVI's 2010 results report to be filed in March 2011.

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

- Employees responsible for the programs at TGVI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

7.2 The Parties agree that the Commission may sever Section 7.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 7.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $4.726 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 7.2 takes effect, the financial schedules in Part IV of this Agreement and the cost of service/revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, will instead be filed on or before June 30, 2010. Concurrent with that report, TGVI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

8. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

The forecast costs of pursuing AES projects in the TGVI service area were included in the Shared Services cost pool, which is allocated pursuant to the Shared Services Agreement among TGI, TGVI and TGW. The costs related to AES projects that would otherwise have been allocated to TGVI have been allocated to TGI's New Energy Solutions Deferral Account pursuant to the Settlement Agreement for the TGI 2010 and 2011 Revenue Requirements. Accordingly, TGVI withdraws its requests for relief in the Application relating to AES. The Parties acknowledge that TGI will be pursuing AES projects within the TGVI

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TERASEN GAS (VANCOUVER ISLAND) INC.
DATED THURSDAY, NOVEMBER 5

service area and agree that the costs incurred by TGI to provide AES will not be recovered in TGVI's natural gas service rates. Any direct costs, sales and marketing O&M and other development costs incurred by TGVI in assisting TGI in pursuit of AES will be directly charged to the TGI New Energy Solutions Deferral Account of TGI by timesheets or other direct charge.

9. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) The new NGV Service Rate Schedule (as set out in the Application Appendix J-4) – the NGV Service Rate Schedule should be approved as filed; and

(b) NGV Grants will be accounted for on a net-of-tax basis in a deferral account and amortized over a five year term (the same treatment as under TGI Rate Schedule 6 (as set out in the Application, Part III, Section C, Tab 3, page 224); and

(c) The marketing costs in support of NGV that are included in the Application are appropriately included in the 2010 and 2011 cost of service.

(d) Upon acceptance of this Agreement by the Commission, TGVI withdraws its request in the Application for the following:

i. Compression and Refueling Service Rate Schedule; and

ii. the Compression Service ("CS") Test; and

iii. NGV non-rate base deferral account for Compression Equipment Costs and Expenses.

The Parties acknowledge that these requests are being withdrawn by TGVI to facilitate a settlement on other issues presented in the Application. The Parties agree that TGVI's withdrawal of its requests regarding NGV is without prejudice to TGVI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGVI intends to develop this area of business and that TGVI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGVI is at liberty to do so.

10. Biogas

Issue No. 3 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Biogas – could be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost."

The Parties agree that, upon acceptance of this Agreement by the Commission, TGVI withdraws its requests in this Application related to Biogas. The Parties acknowledge that these requests are being withdrawn to facilitate a settlement on other issues presented in this Application. The Parties agree that TGVI will bring forward an application (the "Biogas Application") during the test period that will:

(a) Address the economic assessment model; and

(b) Provide Biogas rates (including green rate, transportation rate, etc.); and

(c) Provide for recovery of costs associated with providing Biogas service.

TGVI may include in the Biogas Application any Biogas Projects under development at that time. TGVI is, however, not precluded from applying for Commission approval in respect of individual Biogas Projects at any time, either prior to the Biogas Application or afterwards.

11. CPCN Threshold

Issue No. 6 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "CPCN threshold – why should the threshold increase from $5 million."

The Parties accordingly agree that the CPCN threshold will be $5 million for 2010 and 2011. TGVI's Category C Capital Expenditures forecast for the forecast period will be revised to reflect this change (please see item 13 below).

12. Category A Capital

TGVI had utilized an incorrect inflation rate in the Application when calculating the forecast capital expenditures for Distribution Mains (BCUC IR 1.120.5). The Parties agree to use the correct inflation rate, resulting in a decrease to the Category A Capital Expenditures of $188 thousand in 2010 and $154 thousand in 2011, and an associated decrease in the Revenue Requirement in each of those years, from the amounts set out in the Application.

13. Category C Capital

As a consequence of the CPCN threshold being established at $5 million for 2010 and 2011 (see item 11 above), TGVI will file a CPCN application for the Victoria Regional Office project identified in TGVI's Application. The Category C Capital will consequently be reduced by $5.2 million in 2010 and a further $3.3 million (totaling $8.5 million) in 2011. TGVI will seek deferral treatment for 2011 of the capital costs associated with those projects at the time of filing the CPCN Applications.

The Parties agree that Category C Capital will additionally be reduced by a total of $0.5 million in each of 2010 and 2011. The revised Category C Capital Expenditures, reflecting the removal of the Victoria Regional Office capital expenditures and the $0.5 million IT Capital reduction, are now $4.4 million in 2010 and $4.1 million in 2011.

14. Gross O&M (to be recovered from gas customers)

The Parties agree that the proposed gross O&M recoverable from gas customers is reduced by $0.874 million in 2010 and $0.947 million in 2011, resulting in gross O&M in 2010 of $31.231 million and gross O&M of 2011 of $ 32.702 million. The Parties agree to fix the Gross O&M amounts for the purposes of determination of RDDA and/or RSDA balances at the end of each year. The changes as compared to the Application include the following three components:

1. Reduced Shared Services costs from TGI in the amount of $0.339 million in 2010 and $0.491 million in 2011 as discussed in Item 15 below; and

2. Reduced Corporate Services cost from Terasen Inc. in the amount of $0.535 million in 2010 and $0.540 million in 2011, as discussed in Item 15 below.

3. TGVI inadvertently omitted to include the fixed costs associated with electric Demand charges for general operations of the LNG facility including liquefaction, vapourization, and boil-off compression. The Parties agree that these incremental costs, totalling $83 thousand ($37 thousand for additional electricity and $46 thousand for additional fuel), will be included in the 2011 gross O&M amounts (BCUC IR 1.101.9).

15. Shared Services/Corporate Services

The Parties agree that the amount of Shared Services costs allocated to TGVI from TGI should be reduced by $0.339 million in 2010 and $0.491 million in 2011 as a result of the outcome of the concurrent TGI RRA.

The Parties agree that the amount of Corporate Services costs allocated to TGVI from Terasen Inc. should be reduced by $0.535 million in 2010 and $0.540 million in 2011. As a result of these Corporate Services reductions, and as contemplated in the TGI 2010-2011 RRA Settlement Agreement, the amount of Corporate Services allocated to TGI from Terasen Inc. will increase by a corresponding amount in each year to ensure recovery of all of the combined Corporate Services.

The Parties agree that the current Shared Services Agreement between TGVI and TGW will be discontinued, and acknowledge that TGI will be providing shared services to TGW.

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16. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010, with the exception of:

(a) incorporating the correct updated rates from the depreciation study results in a change in the rate for asset class 475 from 1.62 per cent to 1.94 per cent, and a change in the rate for asset class 477 from 4.92 per cent to 4.60 per cent (BCUC IR 1.146.3); and

(b) the component of those rates that represent recovery of negative salvage (see item 17 below).

Adjusting for the Distribution Asset Classes, negative salvage, and overheads capitalized and capital expenditures changes yields total depreciation expense of $21.8 million in 2010 and $26.0 million in 2011, of which approximately $1.2 million results from the updated Gannett Fleming depreciation study.

The Parties agree that TGVI will undertake an updated depreciation study to be included as part of TGVI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGVI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

17. Negative Salvage Values

On an annual basis, TGVI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment, which was approved as recently as 2004, along with an estimate of the salvage amount to be included in depreciation rates recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGVI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGVI historically, and with this RRA TGVI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($0.343 million and $0.344 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount

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accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGVI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

The Parties agree that TGVI will update its financial schedules to increase the opening balance of the Accumulated Amortization of Contributions in Aid of Construction and correspondingly decrease the opening balance of Accumulated Depreciation by $13.275 million (BCUC IR 2.37.1.1) with no effect on rate base or cost of service.

18. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 per cent for the provision of utility service to ratepayers (BCUC IR 1.112.1).

The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this Agreement. TGVI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

19. Overheads Capitalized

The Parties agree to a change in the overheads capitalized rate to 14 per cent of Gross O&M for 2010 and 2011.

20. International Financial Reporting Standards ("IFRS") 2010 Impact

Issue No. 4 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "International Financial Reporting Standards ("IFRS") – could have no IFRS impact in 2010."

The Parties agree to defer the 2010 revenue requirement impact of IFRS, resulting from Items 25 (b), (c), (d) and (e) in this Agreement, to be reflected in revenue requirements in 2011 up to a maximum of $2.0 million. Amounts, if any, over $2.0 million would be deferred and reflected in revenue requirements after 2011 based on the amortization approved by the Commission at that time.

21. Allocation of 2009 Revenue Surplus Account ("RSA") Balance (Application page 322 Item (7)(b))

The Commission approved the creation of a 2009 Revenue Surplus Account in Order No. G-84-09. TGVI currently forecasts that the RDDA balance will reach zero in 2009 and that a surplus will be recorded in the 2009 RSA. The actual balance in the 2009 RSA will not be known until the Commission approves the 2009 year end balance in the RDDA, pursuant to section 2.10(f) of the Special Direction.

Issue No. 8 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Rate Design – should BC Hydro receive any refund for the expected 2009 RDDA surplus?"

The Parties have considered the issue raised by the Commission Panel. The Parties agree, for the purposes of achieving overall Agreement, that the answer to Commission Panel Issue No. 8 is, "Yes", and that the forecast balance in the 2009 RSA of $2.962 million will be amortized equally over the forecast years 2010 and 2011 to all customers, other than the VIGJV and TGI Squamish Service Area (TGI Squamish), as follows:

(a) $2.677 million to Core Market

(b) $0.246 million to BC Hydro

(c) $0.039 million to TGW

Any variance between the forecast and actual 2009 RSA balance will be captured in the RSDA described below.

22. Rate Stabilization Deferral Account ("RSDA") (Application page 323 Item (7)(c))

Variances between forecast cost of service and actual cost of service, other than O&M, are items that will be "trued up to actual" as per the Special Direction. Gross O&M will be as stated in Item 14, and not "trued up to actual" (i.e. variances from forecast O&M specified in Item 14 will be an at-risk item for the shareholder). The allowed rate of return on Equity will be adjusted to that approved by the Commission during the period of the settlement and will not be trued up to actual. For clarity, this means that approved rate of return on equity percentage will apply to the actual rate base consistent with the methodology employed since 2003 for TGVI.

The Parties agree that TGVI will establish a RSDA to capture:

(a) differences in 2010 and 2011 between:

i. the net revenues received; and

ii. the actual, "trued-up", cost of service, excluding O&M variances from forecast stated in Item 14; and

(b) any Accumulated Revenue Deficiency in the RDDA after December 31, 2009.

The Parties agree that any balance in the RSDA will be amortized into the cost of service after 2011. However, the Parties agree that the following issues will be deferred to a future proceeding:

(a) how any balance in the RSDA will be allocated among customer classes; and

(b) the period over which any balance in the RSDA will be amortized into the cost of service.

RATE DESIGN

23. Rate Design

The Vancouver Island Natural Gas Pipeline Agreement contemplates the Provincial Government Royalty Revenues to TGVI ceasing at the end of 2011. The Parties agree that given the pending loss of Royalty Revenues from the Provincial Government and the strategies to deal with the potential rate shock associated with that circumstance, including potential amalgamation, that it would be appropriate to defer a full scale rate design at this time.

The Parties have differing views on the appropriate rate design. The Parties did not agree on an appropriate rate design, and did not agree on:

(a) Various cost allocation principles;

(b) Revenue to cost ratios; and

(c) The treatment of interruptible transportation revenues.

Instead, the Parties agree that this Negotiated Settlement Agreement is without prejudice to any position Parties may take in the future. The Parties agree that no precedent is set by this Agreement.

24. Rate Proposals

The Parties agree that the proposed core market rate freeze for the two year test period is accepted. The Parties agree to the rates for each customer class is set out in Schedule 1 under Part IV of this Agreement.

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Issue No. 5 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "2010 Rate Changes – in the event that a 2010 rate reduction were to occur as a result of negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability."

The Parties agree that Commission Panel Issue No. 5 is addressed for core market customers.

The Parties agree that the rates for transportation customers, effective January 1, 2010, other than those that have specified rates set out in their contract (VIGJV and TGI Squamish), are as set out below.

(a) BC Hydro

i. Firm Transportation Rate $0.830 per GJ

ii. Summer Interruptible Rate $0.830 per GJ

iii. Winter Interruptible $1.330 per GJ

(b) TG Whistler

i. Firm Transportation Rate $0.930 per GJ

These transport rates are based on TGVI's current allowed return on equity ("ROE") of 9.17 per cent and subject to changes flowing from the Commission's decision in TGVI's concurrent ROE and Capital Structure Application[3], or as adjusted from time to time by the Commission. Nothing in this Agreement precludes TGVI from applying to the Commission in 2010 or 2011 for changes to its allowed ROE and capital structure.

The Parties agree to the following formula to reflect changes in the allowed ROE in the transportation rates, other than those that have specified rates set out in their contract (VIGJV and TGI Squamish). Every 1 basis points difference in the approved ROE as compared to the current ROE of 9.17 per cent will cause the firm and interruptible rates to change in the same direction by 0.034 cents per GJ rounded to the nearest tenth of a cent.

PART III – REQUESTS UNCHANGED FROM THE APPLICATION

The Parties agree to the following items set out in this section, which are consistent with the proposals in TGVI's Application.

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[3] Filed jointly by the Terasen Utilities [TGI, TGVI. and Terasen Gas (Whistler) Inc.] on May 15, 2009.

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25. Accounting Policy Changes as per Application Part III, Section E - Approvals Sought - to be effective January 1, 2010

The Parties agree to the following accounting policy changes, as set out in TGVI's Application:

(a) Training and Feasibility Study Costs to be treated as O&M expense, rather than capital (Application Page 438 and 439, Item 18).

(b) Capitalization of Major Inspection and Overhaul Costs, including the creation of new Asset Classes (Application Page 438 and 439, Item 18).

(c) Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects (Application Page 438 and 439, Item 18).

(d) Capitalization of Depreciation on Assets used in Construction (Application Page 438 and 439, Item 18).

(e) All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Application Page 438 and 439, Item 18).

(f) Adoption of the effective interest method for calculating interest expense on long-term debt (Application Page 438 and 439, Item 18).

26. Various Accounting Related Proposals as per Application Part III, Section E - Approvals Sought effective January 1, 2010

The Parties agree to the following accounting related changes, as set out in TGVI's Application:

(a) Adoption of the Cash Working Capital Lead/Lag Days as set out in the Lead/Lag study (Application page 438, Item 16d).

(b) The treatment of Customer Security Deposits as part of the unfunded debt, instead of as a component of working capital (Application Page 438 and 439 Item 18).

(c) The inclusion of the reserve for bad debts as a component of working capital (Application Page 438 and 439 Item 18).

(d) Consolidated Core Market Administration Expenses (for TGI, TGVI and TGW), including allocation percentages (Application page 438, Item 16e).

27. Tariff Change Proposals as per Application Part III, Section E - Approvals Sought, Item 19

The Parties agree to the following Tariff changes, as set out in TGVI's Application:

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(a) Revised Fee New Customer Application fee from $85 to $25

(b) Revised dishonoured cheque charge from $10 to $20

(c) Revised Fee Meter Testing fee from $50 to $60

(d) Removed special meter reading charge

(e) Removed move meter from inside to outside premises at consumer's request charge

(f) Removed resetting of meter and regulator charge

(g) Removed where services performed at cost charge

(h) Changes to the Standard Terms and Conditions as set out in Part III, Section C, Tab 12 and Appendix J-2 of the Application.

28. <u>Deferral Account Proposals as per Application Part III, Section E - Approvals Sought, Item 17</u>

The Parties agree to the continuation, modification or adoption of the following deferral accounts as set out in TGVI's Application:

(a) Deferral Accounts - No Change:

i. Gas Cost Variance Account (Application page 316, Item (1)).

ii. Insurance variance (Application page 318, Item (3) (a)).

iii. Pension & OPEB variance (Application page 318, Item (3) (b)).

iv. Olympic Security costs (Application page 318, Item (3) (d)).

v. IFRS conversion costs (Application page 318, Item (3) (e)).

vi. PCEC Start Up Costs (Application page 319 Item (5)(a)).

vii. Accounts Amortized in 2010 (Application page 321, Item (6) (c)).

viii. RDDA (Application Page 322 Item (7)(a)).

(b) Deferral Accounts - New:

i. BCUC Levies variance (Application page 318, Item (3) (c)).

ii. Costs of applications (CCE, ROE, RRA) (Application page 319, Item (4)).

iii. IFRS Transitional Deferral Account (Application page 319, Item (5) (b)).

iv. Pension and OPEB funding differences (Application page 320, Item (5) (c)).

v. Gains and Losses on Asset Disposition (Application page 320, Item (5) (d)).

29. RDDA Balance as at December 31, 2008

The Parties agree pursuant to section 2.10 (f) of the Special Direction that the December 31, 2008 year end balance in the RDDA is $7,149,210, as set out in Part III, Section B, Tab 2 of the Application. (Application page 437, Item 12)

30. Cost of Service

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's forecast Cost of Service for 2010 and 2011 will be as set out in Schedule 14, in Part IV of this Agreement, but subject to (a) the need to recover any Accumulated Revenue Deficiency in the RDDA after December 31, 2009 as explained in Part III, Section B, Tab 2 and (b) changes in TGVI's allowed return on equity. (Application page 436, Item 4).

31. Capital

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's forecast capital expenditures for 2010 and 2011 will be as set out in Schedule 42, in Part IV of this Agreement. (Application page 437, Item 9)

32. Revenue

The Parties agree pursuant to section 2.10(a)(i) of the Special Direction that TGVI's revenues will be as per Schedule 14, in Part IV of this Agreement.

33. Customer Segmentation

The Parties agree to accept the customer segmentation as filed in the Application.

34. Mt. Hayes LNG Storage – Storage and Delivery Agreement

The Parties agree to accept Schedule A of Tariff Supplement No. 4 (Storage and Delivery Agreement between TGI and TGVI), as set out in Part III, Section B, Tab 3 of the Application.

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PART IV – REVISED FINANCIAL SCHEDULES

The revised Financial Schedules follow.

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TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 1

CORE MARKET AND TRANSPORTATION RATES
EFFECTIVE JANUARY 1, 2010
In $/GJ

Core Market Rate Class	Approved Rate (in $/GJ) 2009		Approved Rate (in $/GJ) 2010		Approved Rate (in $/GJ) 2011	
	Basic Charge	Variable Charge	Basic Charge	Variable Charge	Basic Charge	Variable Charge
RGS	$ 10.500	$ 14.325	$ 10.500	$ 14.325	$ 10.500	$ 14.325
AGS	$ 40.000	$ 12.373	$ 40.000	$ 12.373	$ 40.000	$ 12.373
SCS-1	$ 9.450	$ 16.940	$ 9.450	$ 16.940	$ 9.450	$ 16.940
SCS-2	$ 33.530	$ 16.455	$ 33.530	$ 16.455	$ 33.530	$ 16.455
LCS-1	$ 61.000	$ 13.353	$ 61.000	$ 13.353	$ 61.000	$ 13.353
LCS-2	$ 97.820	$ 12.311	$ 97.820	$ 12.311	$ 97.820	$ 12.311
LCS-3	$ 201.510	$ 12.015	$ 201.510	$ 12.015	$ 201.510	$ 12.015
HLF	$ 250.000	$ 8.697	$ 250.000	$ 8.697	$ 250.000	$ 8.697
ILF	$ 250.000	$ 10.097	$ 250.000	$ 10.097	$ 250.000	$ 10.097

Transportation Customers	Approved Rate (in $/GJ) 2009	Approved Rate (in $/GJ) 2010	Approved Rate (in $/GJ) 2011
BC Hydro - Firm Rate	$ 0.912	$ 0.830	$ 0.830
BC Hydro - Winter IT Rate	$ 1.557	$ 1.330	$ 1.330
TGW	$ 1.026	$ 0.930	$ 0.930

Note:
1. The rates for Vancouver Island Gas Joint Venture ("VIGJV") and TGI Squamish are set as per their respective transporation service agreements.

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C, Tab 13, Schedule 2

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Surplus	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,636	12,264	-	12,264	(372)	Schedule 15
3	Transportation	21,692	22,946	-	22,946	1,254	Schedule 15
		34,328	35,210	-	35,210	882	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 184,795	$ 179,501	$ -	$ 179,501	$ (5,294)	Schedule 18
6	- Increase / (Decrease)		-	(14,443)	(14,443)	(14,443)	
7	Transportation - Existing Rates	20,126	22,194	-	22,194	2,069	Schedule 18
8	- Increase / (Decrease)			-	-	-	
9	**Total Revenue**	204,921	201,695	(14,443)	187,252	(17,668)	
10	Royalty Credit	(48,701)	(28,095)	-	(28,095)	20,606	
11	GCVA Amortization	3,045	4,162		4,162	1,117	Schedule 58
12	GCVA Additions	-	5,781	-	5,781	5,781	
13	Cost of Gas	129,512	99,314	-	99,314	(30,198)	Schedule 21
14	RACOG Including GCVA Impacts	83,856	81,162		81,162	(2,694)	
15	**Gross Margin**	121,064	120,533	(14,443)	106,090	(14,975)	
16	Operation and Maintenance (allowed)	26,178	26,178	-	26,178	(0)	
17	Transportation Expenses	4,374	3,977	-	3,977	(397)	
18	Operating Leases	828	828	-	828	-	
19	Property Taxes	8,362	8,449	-	8,449	87	Schedule 26
20	Depreciation and Amortization	$32,230	23,017	-	23,017	(9,213)	Schedule 27
21	Removal Costs (Depreciation)	-	-	-	-	-	
22	IFRS Transitional Deferral	-	-	-	-	-	
23	Other Operating Revenue	(1,062)	(893)	-	(893)	169	Schedule 22
24		70,911	61,556	-	61,556	(9,355)	
25	Utility Income Before Income Taxes	50,153	58,977	(14,443)	44,534	(5,619)	
26	Income Taxes	11,905	13,178	(4,331)	8,847	(3,058)	Schedule 30
27	**EARNED RETURN**	$ 40,115	$ 47,666	$ (10,112)	$ 37,554	$ (2,561)	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 30
27	**EARNED RETURN After VINGPA Adjustment**	$ 38,248	$ 45,799	$ (10,112)	$ 35,687	$ (2,561)	
28	**UTILITY RATE BASE**	$ 539,525	$ 540,195	$ (407)	$ 539,788	$ 264	Schedule 8
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	7.11%	8.82%		6.96%	-0.15%	
31	After VINGPA Adjustment	7.09%	8.48%		6.61%	-0.48%	
32	**EARNED RETURN**	$ 40,115	$ 47,666	$ (10,112)	$ 37,554	$ (2,561)	Schedule 68
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 38,248	$ 45,799	$ (10,112)	$ 35,687	$ (2,561)	x-ref Schedule 5

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 3

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Surplus	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,264	12,241	-	12,241	(23)	Schedule 16
3	Transportation	22,946	22,309	-	22,309	(637)	Schedule 16
		35,210	34,550	-	34,550	(660)	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 179,501	$ 179,445	$ -	$ 179,445	$ (56)	Schedule 19
6	- Increase / (Decrease)	(14,443)	-	(42,605)	(42,605)	(28,162)	
7	Transportation - Existing Rates	22,194	20,669	-	20,669	(1,525)	Schedule 19
8	- Increase / (Decrease)	-		-	-	-	
9	**Total Revenue**	187,252	200,114	(42,605)	157,509	(29,743)	
10	Royalty Credit	(28,095)	(35,832)	-	(35,832)	(7,737)	
11	GCVA Amortization	4,162	(4,047)		(4,047)		Schedule 59
12	GCVA Additions	5,781	-	-	-	(5,781)	
13	Cost of Gas Sold	99,314	98,628	-	98,628	(686)	Schedule 21
14	RACOG Including GCVA Impacts	81,162	58,750		58,750	(22,413)	
15	**Gross Margin**	106,090	141,364	(42,605)	98,759	(29,057)	
16	Operation and Maintenance	26,178	26,858	-	26,858	680	Schedule 23
17	Transportation Expenses	3,977	4,015	-	4,015	38	
18	Operating Leases	828	-	-	-	(828)	
19	Property Taxes	8,449	9,119	-	9,119	670	Schedule 26
20	Depreciation and Amortization	23,017	19,202	-	19,202	(3,815)	Schedule 28
21	Removal Costs (Depreciation)	-	343	-	343	343	
22	IFRS Transitional Deferral	-	1,400	-	1,400	1,400	
23	Other Operating Revenue	(893)	(717)	-	(717)	176	Schedule 22
24		61,556	60,220	-	60,220	(1,336)	
25	Utility Income Before Income Taxes	44,534	81,144	(42,606)	38,538	(5,996)	
26	Income Taxes	8,847	13,661	(12,140)	1,521	(7,326)	Schedule 31
27	**EARNED RETURN**	$ 37,554	$ 69,350	$ (30,466)	$ 38,884	$ 1,330	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 31
27	**EARNED RETURN After VINGPA Adjustment**	$ 35,687	$ 67,483	$ (30,466)	$ 37,017	$ 1,330	
28	**UTILITY RATE BASE**	$ 539,788	$ 554,763	$ (750)	$ 554,013	$ 14,224	Schedule 9
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	6.96%	12.50%		7.02%	0.06%	
31	After VINGPA Adjustment	6.61%	12.16%		6.68%	0.07%	
32	**EARNED RETURN**	$ 37,554	$ 69,350	$ (30,466)	$ 38,884	$ 1,330	Schedule 69
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 35,687	$ 67,483	$ (30,466)	$ 37,017	$ 1,330	x-ref Schedule 6

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY INCOME AND EARNED RETURN Schedule 4
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Surplus	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	12,241	12,433	-	12,433	192	Schedule 17
3	Transportation	22,309	22,017	-	22,017	(292)	Schedule 17
		34,550	34,450	-	34,450	(100)	
4	UTILITY REVENUE						
5	Sales - Existing Rates	$ 179,445	$ 182,402	$ -	$ 182,402	$ 2,957	Schedule 20
6	- Increase / (Decrease)	(42,605)	-	(24,603)	(24,603)	18,002	
7	Transportation - Existing Rates	20,669	20,500	-	20,500	(169)	Schedule 20
8	- Increase / (Decrease)	-		-	-	-	
9	**Total Revenue**	157,509	202,902	(24,603)	178,299	20,790	
10	Royalty Credit	(35,832)	(40,091)	-	(40,091)	(4,260)	
11	GCVA Amortization	(4,047)	-	-	-		Schedule 60
12	GCVA Additions	-	-	-	-	-	
13	Cost of Gas Sold (Including Gas Loss)	98,628	107,311	-	107,311	8,683	Schedule 21
14	RACOG Including GCVA Impacts	58,750	67,220		67,220	8,470	
15	**Gross Margin**	98,759	135,682	(24,603)	111,079	12,107	
16	Operation and Maintenance	26,858	28,136	-	28,136	1,277	Schedule 23
17	Transportation Expenses	4,015	4,122	-	4,122	107	
18	Operating Leases	-	-	-	-	-	
19	Property Taxes	9,119	9,564	-	9,564	445	Schedule 26
20	Depreciation and Amortization	19,202	25,232	-	25,232	6,030	Schedule 29
21	Removal Costs (Depreciation)	343	344	-	344	1	
22	IFRS Transitional Deferral	1,400	(1,400)	-	(1,400)	(2,800)	
23	Other Operating Revenue	(717)	(9,752)	-	(9,752)	(9,035)	Schedule 22
24		60,220	56,246	-	56,246	(3,975)	
25	Utility Income Before Income Taxes	38,538	79,437	(24,604)	54,833	16,295	
26	Income Taxes	1,521	10,352	(6,518)	3,834	2,313	Schedule 32
27	**EARNED RETURN**	$ 38,884	$ 70,952	$ (18,086)	$ 52,866	$ 13,982	
28	VINGPA Grind	(1,867)	(1,867)	-	(1,867)	-	Schedule 32
27	**EARNED RETURN After VINGPA Adjustment**	$ 37,017	$ 69,085	$ (18,086)	$ 50,999	$ 13,982	
28	**UTILITY RATE BASE**	$ 554,013	$ 729,375	$ (381)	$ 728,994	$ 174,982	Schedule 10
29	**RATE OF RETURN ON UTILITY RATE BASE**						
30	Before VINGPA Adjustment	7.02%	9.73%		7.25%	0.23%	
31	After VINGPA Adjustment	6.68%	9.47%		7.00%	0.31%	
32	**EARNED RETURN**	$ 38,884	$ 70,952	$ (18,086)	$ 52,866	$ 13,982	Schedule 70
33	VINGPA Adjustment	(1,867)	(1,867)	-	(1,867)	-	
34	**EARNED RETURN After VINGPA Adjustment**	$ 37,017	$ 69,085	$ (18,086)	$ 50,999	$ 13,982	x-ref Schedule 7

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C

Tab 13

INCOME TAXES Schedule 5

FOR THE YEAR ENDING DECEMBER 31, 2009

($000s)

Line No.	Particulars	2009 APPROVED	2009 ----Cost of Service Rates----- Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$36,756	$45,799	($10,112)	$35,687	($1,069)	Schedule 2
3	Deduct - Interest on Debt	(20,325)	(17,759)	4	(17,755)	2,570	
4	Add - O&M Savings	2,127	2,435	-	2,435	308	
5	Add- Non-Tax Ded. Expense (Net)	15,609	6,015	-	6,015	(9,595)	Schedule 33
6	Accounting Income After Tax	34,167	36,489	(10,108)	26,382	(7,786)	
7	Add (Deduct) - Timing Differences	(6,388)	(5,740)	-	(5,740)	648	Schedule 33
8	Taxable Income After Tax	$27,779	$30,750	($10,108)	$20,642	($7,137)	
9		30.000%	30.000%	30.000%	30.000%	0.000%	
10	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
11	Taxable Income	$39,685	$43,928	($14,439)	$29,489	($10,196)	
12	**Total Income Tax**	$ 11,905	$ 13,178	$ (4,332)	$ 8,847	$ (3,058)	x-ref Schedule 2

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 ----Cost of Service Rates----- Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$35,687	$67,484	($30,467)	$37,017	$1,330	Schedule 3
3	Deduct - Interest on Debt	(17,755)	(18,574)	11	(18,563)	(808)	Schedule 12
4	Add - O&M Savings	2,435	-	-	-	(2,435)	
5	Add- Non-Tax Ded. Expense (Net)	6,015	(6,593)	-	(6,593)	(12,608)	Schedule 34
6	Accounting Income After Tax	26,382	42,316	(30,455)	11,860	(14,521)	
7	Add (Deduct) - Timing Differences	(5,740)	(8,044)	-	(8,044)	(2,304)	Schedule 34
8	Taxable Income After Tax	$20,642	$34,272	($30,455)	$3,816	($16,826)	
9		30.000%	28.500%	28.500%	28.500%	-1.500%	
10	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
11	Taxable Income	$29,489	$47,933	($42,595)	$5,338	($24,151)	
12	**Total Income Tax**	$ 8,847	$ 13,661	$ (12,140)	$ 1,521	$ (7,326)	x-ref Schedule 3

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 7

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 ----Cost of Service Rates----- Approved Rates	Required Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$37,017	$69,086	($18,087)	$50,999	$13,982	Schedule 4
3	Deduct - Interest on Debt	(18,563)	(26,136)	10	(26,126)	(7,563)	Schedule 13
4	Add - O&M Savings	-	-	-	-	-	
5	Add- Non-Tax Ded. Expense (Net)	(6,593)	(686)	-	(686)	5,908	Schedule 35
6	Accounting Income After Tax	11,860	42,264	(18,077)	24,187	12,327	
7	Add (Deduct) - Timing Differences	(8,044)	(13,552)	-	(13,552)	(5,509)	Schedule 35
8	Taxable Income After Tax	$3,816	$28,712	($18,077)	$10,635	$6,818	
9		28.500%	26.500%	26.500%	26.500%	-2.000%	
10	1 - Current Income Tax Rate	71.500%	73.500%	73.500%	73.500%	2.000%	
11	Taxable Income	$5,338	$39,064	($24,595)	$14,469	$340,924	
12	**Total Income Tax**	$ 1,521	$ 10,352	$ (6,518)	$ 3,834	$ 2,313	x-ref Schedule 4

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY RATE BASE Schedule 8
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Adjustments	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 737,301	$ 733,157	$ -	$ 733,157	$ (4,144)	Schedule 44
2	Opening Balance Adjustment*	-	208,237	-	208,237	208,237	
3	Gas Plant in Service, Ending	785,862	1,012,319	-	1,012,319	226,458	Schedule 44
4	Accumulated Depreciation Beginning - Plant	(178,559)	(178,029)	-	(178,029)	530	Schedule 50
5	Opening Balance Adjustment*	-	(45,847)	-	(45,847)	(45,847)	
6	Accumulated Depreciation Ending - Plant	(196,352)	(245,154)	-	(245,154)	(48,802)	Schedule 50
7	CIAC, Beginning	(60,835)	(60,835)	-	(60,835)	(0)	Schedule 55
8	Opening Balance Adjustment*		(208,237)	-	(208,237)	(208,237)	
9	CIAC, Ending	(53,475)	(278,861)	-	(278,861)	(225,386)	Schedule 55
10	Accumulated Amortization Beginning - CIAC	1,990	1,990	-	1,990	(0)	Schedule 55
11	Opening Balance Adjustment*		45,847	-	45,847	45,847	
12	Accumulated Amortization Ending - CIAC	-	50,380	-	50,380	50,380	Schedule 55
13	Net Plant in Service, Mid-Year	$ 517,966	$ 517,483	$ -	$ 517,483	$ (482)	
14	Adjustment to 13-Month Average	817	6,489	-	6,489	5,672	
15	Allocated Common Plant to TGW, Mid-Year	(104)	(104)	-	(104)	0	
16	Work in Progress, No AFUDC	1,812	3,652	-	3,652	1,840	
17	Unamortized Deferred Charges	6,246	3,689	-	3,689	(2,557)	Schedule 58
18	Cash Working Capital	(2,100)	(2,589)	(407)	(2,996)	(895)	Schedule 61
19	Other Working Capital (incl. Construction Advances)	14,889	11,575	-	11,575	(3,313)	Schedule 61
20	Future Income Taxes Regulatory Asset	-	58,802	-	58,802	58,802	Schedule 67
21	Future Income Taxes Liability	-	(58,802)	-	(58,802)	(58,802)	Schedule 67
22	**Utility Rate Base**	$ 539,525	$ 540,195	$ (407)	$ 539,788	$ 264	

*Adjustment to remove CIAC from Gas Plant in Service, and Accumulated Amortization of CIAC from Accumulated Depreciaton

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY RATE BASE Schedule 9
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Adjustments	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 733,157	$ 1,012,319	$ -	$ 1,012,319	$ 279,162	Schedule 46
2	Opening Balance Adjustment	208,237	-	-	-	(208,237)	
3	Gas Plant in Service, Ending	1,012,319	1,036,234	-	1,036,234	23,915	Schedule 46
4	Accumulated Depreciation Beginning - Plant	(178,029)	(245,154)	-	(245,154)	(67,125)	Schedule 52
5	Opening Balance Adjustment*	(45,847)	(1,379)	-	(1,379)	44,468	
6	Accumulated Depreciation Ending - Plant	(245,154)	(270,987)	-	(270,987)	(25,833)	Schedule 52
7	CIAC, Beginning	(60,835)	(278,861)	-	(278,861)	(218,026)	Schedule 56
8	Opening Balance Adjustment	(208,237)	-	-	-	208,237	
9	CIAC, Ending	(278,861)	(275,728)	-	(275,728)	3,133	Schedule 56
10	Accumulated Amortization Beginning - CIAC	1,990	50,380	-	50,380	48,390	Schedule 56
11	Opening Balance Adjustment	45,847	-	-	-	(45,847)	
12	Accumulated Amortization Ending - CIAC	50,380	54,795	-	54,795	4,415	Schedule 56
13	Net Plant in Service, Mid-Year	$ 517,483	$ 540,809	$ -	$ 540,809	$ 23,326	
14	Adjustment to 13-Month Average	6,489	-	-	-	(6,489)	
15	Allocated Common Plant to TGW, Mid-Year	(104)	-	-	-	104	
16	Work in Progress, No AFUDC	3,652	3,608	-	3,608	(44)	
17	Unamortized Deferred Charges	3,689	495	-	495	(3,194)	Schedule 59
18	Cash Working Capital	(2,996)	318	(750)	(432)	2,563	Schedule 62
19	Other Working Capital (incl. Construction Advances)	11,575	9,533	-	9,533	(2,043)	Schedule 62
20	Future Income Taxes Regulatory Asset	58,802	60,101	-	60,101	1,298	Schedule 67
21	Future Income Taxes Liability	(58,802)	(60,101)	-	(60,101)	(1,298)	Schedule 67
22	**Utility Rate Base**	$ 539,788	$ 554,763	$ (750)	$ 554,013	$ 14,224	

*Adjustment relates to transfer of accumulated loss on General Plant to IFRS Transitional Adjustments deferral account

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 10

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Adjustments	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 1,012,319	$ 1,036,234	$ -	$ 1,036,234	$ 23,915	Schedule 48
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	1,036,234	1,274,815	-	1,274,815	238,581	Schedule 48
4	Accumulated Depreciation Beginning - Plant	(245,154)	(270,987)	-	(270,987)	(25,833)	Schedule 54
5	Opening Balance Adjustment	(1,379)	-	-	-	1,379	
6	Accumulated Depreciation Ending - Plant	(270,987)	(299,264)	-	(299,264)	(28,277)	Schedule 54
7	CIAC, Beginning	(278,861)	(275,728)	-	(275,728)	3,133	Schedule 57
8	Opening Balance Adjustment	-	-	-	-	-	
9	CIAC, Ending	(275,728)	(276,176)	-	(276,176)	(448)	Schedule 57
10	Accumulated Amortization Beginning - CIAC	50,380	54,795	-	54,795	4,415	Schedule 57
11	Opening Balance Adjustment	-	-	-	-	-	
12	Accumulated Amortization Ending - CIAC	54,795	59,218	-	59,218	4,423	Schedule 57
13	Net Plant in Service, Mid-Year	$ 540,809	$ 651,454	$ -	$ 651,454	$ 110,644	
						0	
14	Adjustment to 13-Month Average	-	56,712	-	56,712	56,712	
15	Allocated Common Plant to TGW, Mid-Year	-	-	-	-	-	
16	Work in Progress, No AFUDC	3,608	3,608	-	3,608	-	
17	Unamortized Deferred Charges	495	4,908	-	4,908	4,413	Schedule 60
18	Cash Working Capital	(432)	516	(381)	135	567	Schedule 63
19	Other Working Capital (incl. Construction Advances)	9,533	12,178	-	12,178	2,645	Schedule 63
20	Future Income Taxes Regulatory Asset	60,101	63,889	-	63,889	3,788	Schedule 67
21	Future Income Taxes Liability	(60,101)	(63,889)	-	(63,889)	(3,788)	Schedule 67
22	**Utility Rate Base**	$ 554,013	$ 729,375	$ (381)	$ 728,994	$ 174,982	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 11

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$260,940	48.300%	5.956%	2.880%	15,541	x-ref Schedule 5
3	Unfunded Debt			63,177	11.700%	1.500%	0.180%	948	x-ref Schedule 5
4	Common Equity			216,078	40.000%	13.841%	5.536%	29,907	
5	Before Sub Debt Interest	Schedule 39		$540,195	100.000%		8.596%	$46,396	
6	Sub Debt Interest							1,270	x-ref Schedule 5
7	Total						8.824%	$47,666	
8	2009 COST OF SERVICE RATES - PROJECTION								
9	Long-Term Debt			$260,940	48.340%	5.956%	2.880%	15,541	x-ref Schedule 5
10	Unfunded Debt		$63,177						
11	Adjustment, Revised Rates		(244)	62,933	11.660%	1.500%	0.170%	944	x-ref Schedule 5
13	Common Equity			215,915	40.000%	9.170%	3.670%	19,799	
14	Before Sub Debt Interest	Schedule 39		$539,788	100.000%		6.720%	36,284	x-ref Schedule 5
15	Sub Debt Interest							1,270	
16							6.957%	37,554	x-ref Schedule 2, 5, 14

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 12

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$289,659	52.210%	5.950%	3.110%	17,233	x-ref Schedule 6
3	Unfunded Debt			43,199	7.790%	2.500%	0.190%	1,080	x-ref Schedule 6
4	Common Equity			221,905	40.000%	22.882%	9.153%	50,776	
5		Schedule 40		$554,763	100.000%		12.453%	$69,089	
6								261	x-ref Schedule 6
7							12.501%	$69,350	
8	2010 COST OF SERVICE RATES								
9	Long-Term Debt			$289,659	52.280%	5.950%	3.110%	17,233	x-ref Schedule 6
10	Unfunded Debt		$43,199						
11	Adjustment, Revised Rates		(450)	42,749	7.720%	2.500%	0.190%	1,069	x-ref Schedule 6
13	Common Equity			221,605	40.000%	9.170%	3.670%	20,321	
14		Schedule 40		$554,013	100.000%		6.970%	38,623	x-ref Schedule 6
15								261	
16							7.019%	38,884	x-ref Schedule 3, 6, 14

TERASEN GAS (VANCOUVER ISLAND) INC.

Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 13

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt			$390,731	53.570%	6.119%	3.278%	23,909	x-ref Schedule 7
3	Unfunded Debt			46,894	6.430%	4.750%	0.305%	2,227	x-ref Schedule 7
4	Common Equity			291,750	40.000%	15.361%	6.145%	44,816	
5		Schedule 41							
6									
7				$729,375	100.000%		9.728%	$70,953	
8	2011 COST OF SERVICE RATES								
9	Long-Term Debt			$390,731	53.600%	6.119%	3.280%	23,909	x-ref Schedule 7
10	Unfunded Debt		$46,894						
11	Adjustment, Revised Rates		(229)	46,665	6.400%	4.750%	0.304%	2,217	x-ref Schedule 7
13	Common Equity			291,598	40.000%	9.170%	3.668%	26,740	
14		Schedule 41							
15									
16				$728,994	100.000%		7.252%	52,866	x-ref Schedule 4, 7, 14

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Approved Rates	Surplus	Cost of Service Rates	Approved Rates	Surplus	Cost of Service Rates	Approved Rates	Surplus	Cost of Service Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	ENERGY VOLUMES (TJ)										
2	Sales	12,264	-	12,264	12,241	-	12,241	12,433	-	12,433	Schedules 15, 16, 17
3	Transportation	22,946	-	22,946	22,309	-	22,309	22,017	-	22,017	Schedules 15, 16, 17
4		35,210	-	35,210	34,550	-	34,550	34,450	-	34,450	
5	Average Rate per GJ										
6	Sales	$14.636		$13.459	$14.659		$11.179	$14.671		$12.692	
7	Transportation	$0.967		$0.967	$0.926		$0.926	$0.931		$0.931	
8	Average	$5.728		$5.318	$5.792		$4.559	$5.890		$5.176	
9	Sales - Present Rates	$179,501	$0	$179,501	$179,445	$0	$179,445	$182,402	$0	$182,402	Schedules 18, 19, 20
10	- Increase / (Decrease)	-	(14,443)	(14,443)	-	(42,605)	(42,605)	-	(24,603)	(24,603)	
11	Transportation - Present Rates	22,194	-	22,194	20,669	-	20,669	20,500	-	20,500	Schedules 18, 19, 20
12	- Increase / (Decrease)	-	-	-	-	-	-	-	-	-	
13	Total Revenue	201,695	(14,443)	187,252	200,114	(42,606)	157,508	202,902	(24,603)	178,299	
14	Royalty Credit	(28,095)	-	(28,095)	(35,832)	-	(35,832)	(40,091)	-	(40,091)	
15	GCVA Amortization	4,162		4,162	(4,047)		(4,047)	-	-	-	
16	GCVA Additions	5,781	-	5,781	-	-	-	-	-	-	
17	Cost of Gas	99,314	-	99,314	98,628	-	98,628	107,311	-	107,311	Schedule 21
18	RACOG Including GCVA Impacts	81,162	-	81,162	58,750	-	58,750	67,220	-	67,220	
19	Gross Margin	120,533	(14,443)	106,090	141,364	(42,606)	98,758	135,682	(24,603)	111,079	
20	Operation and Maintenance	26,178	-	26,178	26,858	-	26,858	28,136	-	28,136	
21	Transportation Expenses	3,977	-	3,977	4,015	-	4,015	4,122	-	4,122	
22	Operating Leases	828	-	828	-	-	-	-	-	-	
23	Property and Sundry Taxes	8,449	-	8,449	9,119	-	9,119	9,564	-	9,564	Schedule 26
24	Depreciation and Amortization	23,017	-	23,017	19,202	-	19,202	25,232	-	25,232	Schedules 27, 28, 29
25	Removal Costs (Depreciation)	-	-	-	343	-	343	344	-	344	
26	IFRS Transitional Deferral	-	-	-	1,400	-	1,400	(1,400)	-	(1,400)	
27	Other Operating Revenue	(893)	-	(893)	(717)	-	(717)	(9,752)	-	(9,752)	Schedule 22
28		61,556	-	61,556	60,220	0	60,220	56,246	-	56,246	
29	Utility Income Before Income Taxes	58,977	(14,443)	44,534	81,144	(42,606)	38,538	79,437	(24,604)	54,833	
30	Income Taxes	13,178	(4,331)	8,847	13,661	(12,140)	1,521	10,352	(6,518)	3,834	Schedules 30, 31, 32
33	EARNED RETURN after VINGPA Adjustment	45,799	($10,112)	$35,687	$67,483	($30,466)	$37,017	$69,085	($18,086)	$50,999	
34	UTILITY RATE BASE	$540,195	($407)	$539,788	$554,763	($750)	$554,013	$729,375	($381)	$728,994	Schedules 39, 40, 41
35	RATE OF RETURN ON UTILITY RATE BASE										
36	Before VINGPA Adjustment	8.82%		6.96%	12.50%		7.02%	9.73%		7.25%	
37	AFter VINGPA Adjustment	8.48%		6.61%	12.16%		6.68%	9.47%		7.00%	
38	EARNED RETURN	47,666	(10,112)	37,554	69,350	(30,466)	38,884	70,952	(18,086)	52,866	
39	VINGPA Adjustment	(1,867)	-	(1,867)	(1,867)	-	(1,867)	(1,867)	-	(1,867)	
40	EARNED RETURN after VINGPA Adjustment	45,799	(10,112)	35,687	67,483	(30,466)	37,017	69,085	(18,086)	50,999	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2009

Line No.	Particulars	2009 APPROVED	2009 Terajoules Core and Non-Core	Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	5,116.8	4,859.0	0.0	4,859.0	(257.8)	
3	AGS	1,150.8	1,129.6		1,129.6	(21.2)	
4	SCS1	361.1	446.5		446.5	85.4	
5	SCS2	548.9	501.4		501.4	(47.5)	
6	LCS1	1,362.4	1,344.4		1,344.4	(18.0)	
7	LCS2	1,265.1	1,314.9		1,314.9	49.8	
8	LCS3	2,535.6	2,421.9		2,421.9	(113.7)	
9	Residential & Commercial sub-total	12,340.7	12,017.7	0.0	12,017.7	(323.0)	
10	HLF	175.5	129.2		129.2	(46.3)	
11	ILF	119.7	117.1		117.1	(2.6)	
12	Total Core	12,635.9	12,264.0	0.0	12,264.0	(371.9)	x-ref Schedule 2, 14
13	Transportation Service						
14	BCH	16,425.0	16,567.9	0.0	16,567.9	142.9	
15	TGW	1,919.6	1,875.5	0.0	1,875.5	(44.1)	
16	VIGJV	2,920.0	0.0	4,098.0	4,098.0	1,178.0	
17	TG Squamish	427.8	0.0	404.7	404.7	(23.1)	
18	Total Transportation Service	21,692.4	18,443.4	4,502.7	22,946.1	1,253.7	x-ref Schedule 2, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	34,328.2	30,707.4	4,502.7	35,210.1	881.9	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 16

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	2009 PROJECTION	2010 Terajoules Core and Non-Core	Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	4,859.0	4,891.8	0.0	4,891.8	32.8	
3	AGS	1,129.6	1,110.3		1,110.3	(19.3)	
4	SCS1	446.5	406.2		406.2	(40.3)	
5	SCS2	501.4	483.7		483.7	(17.7)	
6	LCS1	1,344.4	1,329.4		1,329.4	(15.0)	
7	LCS2	1,314.9	1,383.5		1,383.5	68.6	
8	LCS3	2,421.9	2,383.5		2,383.5	(38.4)	
9	Residential & Commercial sub-total	12,017.7	11,988.4	0.0	11,988.4	(29.3)	
10	HLF	129.2	132.4		132.4	3.2	
11	ILF	117.1	120.5		120.5	3.4	
12	Total Core	12,264.0	12,241.3	0.0	12,241.3	(22.7)	x-ref Schedule 3, 14
13	Transportation Service						
14	BCH	16,567.9	18,250.0	0.0	18,250.0	1,682.1	
15	TGW	1,875.5	725.2	0.0	725.2	(1,150.3)	
16	VIGJV	4,098.0	0.0	2,920.0	2,920.0	(1,178.0)	
17	TG Squamish	404.7	0.0	413.4	413.4	8.7	
18	Total Transportation Service	22,946.1	18,975.2	3,333.4	22,308.6	(637.5)	x-ref Schedule 3, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	35,210.1	31,216.5	3,333.4	34,549.9	(660.2)	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 17

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	2010 FORECAST	2011 Terajoules Core and Non-Core	Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Core						
2	RGS	4,891.8	5,015.3	0.0	5,015.3	123.5	
3	AGS	1,110.3	1,116.6		1,116.6	6.3	
4	SCS1	406.2	414.4		414.4	8.2	
5	SCS2	483.7	485.2		485.2	1.5	
6	LCS1	1,329.4	1,334.2		1,334.2	4.8	
7	LCS2	1,383.5	1,396.8		1,396.8	13.3	
8	LCS3	2,383.5	2,417.2		2,417.2	33.7	
9	Residential & Commercial sub-total	11,988.4	12,179.7	0.0	12,179.7	191.3	
10	HLF	132.4	132.4		132.4	0.0	
11	ILF	120.5	120.5		120.5	0.0	
12	Total Core	12,241.3	12,432.6	0.0	12,432.6	191.3	x-ref Schedule 4, 14
13	Transportation Service						
14	BCH	18,250.0	17,945.0	0.0	17,945.0	(305.0)	
15	TGW	725.2	729.9	0.0	729.9	4.7	
16	VIGJV	2,920.0	0.0	2,920.0	2,920.0	0.0	
17	TG Squamish	413.4	0.0	422.3	422.3	8.9	
18	Total Transportation Service	22,308.6	18,674.9	3,342.3	22,017.2	(291.4)	x-ref Schedule 4, 14
19	**TOTAL SALES AND TRANSPORTATION SERVICES**	34,549.9	31,107.5	3,342.3	34,449.8	(100.1)	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 18

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	RGS	$84,300	$80,487	$0	$80,487	($3,813)	
3	AGS	14,644	14,399		14,399	(245)	
4	SCS1	6,627	8,113		8,113	1,486	
5	SCS2	9,738	8,826		8,826	(912)	
6	LCS1	19,264	18,902		18,902	(362)	
7	LCS2	16,203	16,740		16,740	537	
8	LCS3	30,811	29,410		29,410	(1,401)	
9	Residential & Commercial sub-total	181,588	176,878	-	176,878	(4,710)	
10	HLF	1,975	1,417	-	1,417	(557)	
11	ILF	1,233	1,206		1,206	(26)	
		3,207	2,624	-	2,624	(584)	
12	Total Core Sales	184,795	179,501	-	179,501	(5,294)	x-ref Schedules 2, 14
13	Transportation Service						
14	BCH	$14,980	16,189	-	16,189	1,209	
15	TGW	1,970	1,739	-	1,739	(230)	
16	VIGJV	2,727	-	3,841	3,841	1,114	
17	TG Squamish	449	-	425	425	(24)	
18	Total Core and Transportation Service	20,126	17,928	4,266	22,194	2,069	x-ref Schedules 2, 14
19	TOTAL SALES AND TRANSPORTATION SERVICE	$204,921	$197,430	$4,266	$201,696	($3,225)	x-ref Schedules 65

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
REVENUE Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference	$'s per GJ (effective rates)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Core Sales**							
2	RGS	$80,487	$81,286	$0	$81,286	$799		$16.617
3	AGS	14,399	14,160		14,160	(239)		12.753
4	SCS1	8,113	7,461		7,461	(651)		18.369
5	SCS2	8,826	8,518		8,518	(307)		17.611
6	LCS1	18,902	18,744		18,744	(159)		14.099
7	LCS2	16,740	17,646		17,646	905		12.754
8	LCS3	29,410	28,931		28,931	(479)		12.138
9	Residential & Commercial sub-total	176,878	176,746	-	176,746	(132)		
10	HLF	1,417	1,459	-	1,459	41		11.018
11	ILF	1,206	1,241		1,241	34		10.296
		2,624	2,699	-	2,699	76		
12	Total Core Sales	179,501	179,445	-	179,445	(56)	x-ref Schedules 3, 14	
13	Transportation Service							
14	BCH	16,189	15,148	-	15,148	(1,041)		0.830
15	TGW	1,739	2,359	-	2,359	620		3.253
16	VIGJV	3,841	-	2,728	2,728	(1,113)		0.934
17	TG Squamish	425	-	434	434	9		1.050
18	Total Core and Transportation Service	22,194	17,507	3,162	20,669	(1,525)	x-ref Schedules 3, 14	
19	TOTAL SALES AND TRANSPORTATION SERVICE	$201,696	$196,952	$3,162	$200,114	($1,581)	x-ref Schedules 65	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 20

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Gas Sales Revenue At Approved Rates: Core and Transportation	Special Rates	Total	Change	Reference	$'s per GJ (effective rates)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Core Sales**							
2	RGS	$81,286	$83,340	$0	$83,340	$2,053		$16.617
3	AGS	14,160	14,240		14,240	80		12.753
4	SCS1	7,461	7,612		7,612	151		18.370
5	SCS2	8,518	8,546		8,546	28		17.614
6	LCS1	18,744	18,812		18,812	68		14.100
7	LCS2	17,646	17,814		17,814	169		12.754
8	LCS3	28,931	29,337		29,337	407		12.137
9	Residential & Commercial sub-total	176,746	179,703	-	179,703	2,957		
10	HLF	1,459	1,459	-	1,459	-		11.018
11	ILF	1,241	1,241		1,241	-		10.296
		2,699	2,699	-	2,699	-		
12	Total Core Sales	179,445	182,402	-	182,402	2,957	x-ref Schedules 4, 14	
13	Transportation Service							
14	BCH	15,148	14,894	-	14,894	(253)		0.830
15	TGW	2,359	2,386	-	2,386	27		3.269
16	VIGJV	2,728	-	2,776	2,776	48		0.951
17	TG Squamish	434	-	443	443	9		1.050
18	Total Core and Transportation Service	20,669	17,281	3,219	20,500	(169)	x-ref Schedules 4, 14	
19	TOTAL SALES AND TRANSPORTATION SERVICE	$200,114	$199,683	$3,219	$202,902	$2,788	x-ref Schedules 65	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 21

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Gas Costs Core and Non-Core	2009 Special Rates	2009 Total	2010 Gas Costs Core and Non-Core	2010 Special Rates	2010 Total	2011 Gas Costs Core and Non-Core	2011 Special Rates	2011 Total	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	**Core**										
2	RGS	39,348	$0	$39,348	$39,414	$0	$39,414	43,289	$0	$43,289	
3	AGS	9,147		9,147	8,946		8,946	9,638		9,638	
4	SCS1	3,616		3,616	3,272		3,272	3,577		3,577	
5	SCS2	4,061		4,061	3,897		3,897	4,188		4,188	
6	LCS1	10,887		10,887	10,711		10,711	11,516		11,516	
7	LCS2	10,648		10,648	11,147		11,147	12,056		12,056	
8	LCS3	19,613		19,613	19,204		19,204	20,864		20,864	
9	Residential & Commercial sub-total	97,320	-	97,320	96,591	-	96,591	105,128	-	105,128	
10	HLF	1,046		1,046	1,066		1,066	1,143		1,143	
11	ILF	948		948	971		971	1,040		1,040	
12	Industrial Subtotal	1,994	-	1,994	2,037	-	2,037	2,183	-	2,183	
13	Total Core	99,314	-	99,314	98,628	-	98,628	107,311	-	107,311	x-ref Schedules 2, 3, 4, 14
14	Unit Cost of Gas before Royalty Credit and GCVA	$8.098		$8.098	$8.057		$8.057	$8.631		$8.631	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C Tab 13 Schedule 22

OTHER OPERATING REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Operating Revenue**				
2	Late Payment Charge	$368	$340	$345	
3	Connection Charge	519	370	380	
4	NSF Returned Cheque Charges	4	5	5	
5	Other Recoveries	2	2	2	
6	LNG Mitigation Revenue	0	0	9,020	
7	Total Other Operating Revenue	$893	$717	$9,752	x-ref Schedules 2, 3, 4, 14, 65

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW — Schedule 23
($000)

Line No.	Particulars (1)	PROJECTION 2009 (3)	FORECAST 2010 (4)	FORECAST 2011 (5)	
1	M&E Costs	$ 3,996	$ 4,225	$ 3,868	
2	COPE Costs	63	109	110	
3	IBEW Costs	4,425	4,486	5,451	
4	**Labour Costs**	**8,484**	**8,819**	**9,429**	
5	Vehicle Costs	610	667	722	
6	Employee Expenses	522	567	587	
7	Materials and Supplies	956	1,338	1,395	
8	Computer Costs	379	302	231	
9	Fees and Administration Costs	8,868	11,387	11,911	
10	Contractor Costs	8,049	7,076	7,125	
11	Facilities	2,114	2,169	2,416	
12	Recoveries & Revenue	(962)	(1,093)	(1,115)	
13	**Non-Labour Costs**	**20,537**	**22,412**	**23,273**	
14	**Total Gross O&M Expenses**	**29,021**	**31,231**	**32,702**	
15	Allocation to Terasen Gas Whistler	(245)	-	-	
16	**Total Gross O&M Expenses net of allocation to TGW**	**28,776**	**31,231**	**32,702**	
17	Less: Capitalized Overhead	(5,033)	(4,372)	(4,567)	
18	**Total O&M Expenses**	**$ 23,743**	**$ 26,858**	**$ 28,136**	x-ref Schedules 3, 4, 14

Note: 2009 numbers are projected actual as opposed to approved

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW Schedule 24
($000s)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011
	(1)	(2)	(3)	(4)	(5)
1	*Operating*				
2	Distribution Supervision	100-11	$ 1,741	$ 1,909	$ 1,951
3	Distribution Supervision Total	100-10	1,741	1,909	1,951
4	Operation Centre - Distribution	100-21	(0)	507	526
5	Preventative Maintenance - Distribution	100-23	228	222	172
6	Distribution Operations - General	100-24	868	766	795
7	Meter Exchange	100-25	(0)	-	-
8	Emergency Management	100-26	1,285	1,217	1,266
9	Distribution Operations Total	100-20	2,380	2,712	2,759
10	Distribution Corrective - Meters	100-31	286	161	169
11	Distribution Corrective - Propane	100-32	-	-	-
12	Distribution Corrective - Leak Repair	100-33	151	135	139
13	Distribution Corrective - Stations	100-34	36	42	40
14	Distribution Corrective - General	100-35	124	72	75
15	Distribution Maintenance Total	100-30	597	409	422
16	**Distribution Total**	**100**	**4,719**	**5,030**	**5,132**
17	Pipeline Operation - Operations	200-21	2,013	1,439	1,346
18	Right of Way	200-22	157	172	175
19	Compression - Operations	200-23	942	1,074	1,004
20	Gas Control	200-24	-	-	-
21	Transmission - Operation	200-20	3,112	2,685	2,525
22	Pipeline Operation - Maintenance	200-31	511	589	610
23	Compression - Maintenance	200-33	1,322	614	671
24	Transmission - Maintenance	200-30	1,833	1,202	1,281
25	**Transmission Total**	**200**	**4,945**	**3,887**	**3,806**
26	**Mt. Hayes**	300-11	**-**	**395**	**1,685**
27	**LNG Total**	**300**	**-**	**395**	**1,685**
26	Measurement Operations	400-11	461	468	527
27	Measurement - Operation	400-10	461	468	527
28	Measurement Maintenance	400-21	591	603	603
29	Measurement - Maintenance	400-20	591	603	603
30	**Measurement**	**400**	**1,053**	**1,071**	**1,130**
31	Facilities Management	500-10	1,487	1,521	1,596
32	Operations Engineering	500-30	270	305	310
33	System Integrity	500-50	154	206	210
34	**General Operations Total**	**500**	**1,912**	**2,031**	**2,116**
35	**Total Operating**		**12,628**	**12,414**	**13,869**

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D) | Schedule 25
($000s)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	
	(1)	(2)	(3)	(4)	(5)	
1	*General & Administration*					
2	Corporate & Marketing Communications	600-30	497	0	0	
3	**Marketing Total**	**600**	**497**	**0**	**0**	
4	Customer Care - Supervision	700-10	-	-	-	
5	Customer Contact - ABSU contract	700-20	5,133	5,277	5,480	
6	Bad Debt Management and Administration	700-30	482	259	276	
7	Customer Management & Sales	700-40	1,087	1,140	1,168	
8	**Customer Care Total**	**700**	**6,702**	**6,676**	**6,923**	
9	Application Management	800-20	584	433	438	
10	**Business & IT Services Total**	**800**	**584**	**433**	**438**	
11	Corporate Administration	900-10	7,310	10,076	10,345	
12	Public Affairs	900-30	177	270	270	
13	Human Resource	900-50	-	-	-	
14	Other Post Employment Benefit	900-60	1,123	1,362	858	
15	**Administration & General Total**	**900**	**8,610**	**11,708**	**11,473**	
16	**Total General & Administration**		**16,393**	**18,817**	**18,834**	
17	**Total Gross O&M Expenses**		**29,021**	**31,231**	**32,702**	
18	Allocation to Terasen Gas Whistler		(245)	-	-	
19	**Total Gross O&M Expenses net of allocation to TGW**		**28,776**	**31,231**	**32,702**	
20	Less: Capitalized Overhead		(5,033)	(4,372)	(4,567)	
21	**Total O&M Expenses**		**$ 23,743**	**$ 26,858**	**$ 28,136**	x-ref Schedules 3, 4, 14

Note: 2009 numbers are projected actual as opposed to approved

PROPERTY AND SUNDRY TAXES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Expenses	2010 Expenses	2011 Expenses	
	(1)	(3)	(4)	(5)	
1	Property Taxes				
2	1% in Lieu of General Municipal Tax	$1,522	$1,652	$1,655	
3	General, School and Other	6,927	7,468	7,909	
4	Total	$8,449	$9,119	$9,564	x-ref Schedules 2, 3, 4, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
DEPRECIATION AND AMORTIZATION EXPENSES | Schedule 27
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars (1)	2009 APPROVED (2)	2009 Projection (3)	Change (4)	Reference (5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$19,242	$23,798	$4,556	Schedule 50
4	Less: Depreciation Expense Allocated to TGW	(22)	(22)	-	
5	Less: Amortization of Contributions in Aid of Construction	1,990	(2,545)	(4,535)	Schedule 55
6		21,210	21,231	21	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	$4,790	$5,949	$1,158	Schedule 58
9	Amortization of RDDA	9,275	-	(9,275)	
10	Amortization Expense Including GCVA	14,065	5,949	(8,117)	
11	Less: GCVA (Cost of Gas Item)	(3,045)	(4,162)	($1,117)	Schedule 58
12	Adjusted Total Amoritzation Expense	11,020	1,787	(9,234)	
13	TOTAL	$32,230	$23,017	($9,213)	x-ref Schedules 2, 14. 33

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 28

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$23,798	$26,231	$2,432	Schedule 52
4	Less: Depreciation Expense Allocated to TGW	(22)	-	(22)	
5	Less: Amortization of Contributions in Aid of Construction	(2,545)	(4,415)	(1,870)	Schedule 56
6		21,231	21,816	562	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	$5,949	($5,179)	($11,128)	Schedule 59
9	Amortization of 2009 Revenue Surplus	-	(1,481)	(1,481)	Schedule 59
10		5,949	(6,660)	(12,609)	
11	Less: GCVA (Cost of Gas Item)	(4,162)	4,047	8,209	Schedule 59
12	Adjusted Total Amoritzation Expense	1,787	(2,614)	(4,400)	
13	TOTAL	$23,017	$19,202	($3,816)	x-ref Schedules 3, 14, 34

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Schedule 29

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2	Total Depreciation Expense	$26,231	$30,409	$4,179	Schedule 54
4	Less: Depreciation Expense Allocated to TGW	-	-	-	
5	Less: Amortization of Contributions in Aid of Construction	(4,415)	(4,423)	(8)	Schedule 57
6		21,816	25,986	4,171	
7	**Amortization Expense**				
8	Amortization of Deferred Charges	($5,179)	$727	$5,907	Schedule 60
9	Amortization of 2009 Revenue Surplus	(1,481)	(1,481)	-	Schedule 60
10		(6,660)	(754)	5,907	
11	Less: GCVA (Cost of Gas Item)	4,047	-	(4,047)	Schedule 60
12	Adjusted Total Amoritzation Expense	(2,614)	(754)	1,860	
13	TOTAL	$19,202	$25,232	6,030	x-ref Schedules 4, 14, 35

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 30

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Cost of Service Rates	2009 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$36,756	$45,799	($10,112)	$35,687	($1,069)	Schedule 2
3	Deduct - Interest on Debt	(20,325)	(17,759)	4	(17,755)	2,570	
4	Add - O&M Savings	2,127	2,435	-	2,435	308	
5	Add- Non-Tax Ded. Expense (Net)	15,609	6,015	-	6,015	(9,595)	Schedule 33
6	Accounting Income After Tax	34,167	36,489	(10,108)	26,382	(7,786)	
7	Add (Deduct) - Timing Differences	(6,388)	(5,740)	-	(5,740)	648	Schedule 33
8	Taxable Income After Tax	$27,779	$30,750	($10,108)	20,642	($7,137)	
9		30.000%	30.000%	30.000%	30.000%	0.000%	
10	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
11	Taxable Income	$39,685	$43,928	($14,439)	$29,489	($10,196)	
12	Income Tax - Current	$11,905	$13,178	($4,331)	$8,847	($3,058)	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$11,905	$13,178	($4,331)	$8,847	$26,331	x-ref Schedules 2, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
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Schedule 31

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Cost of Service Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$35,687	$67,483	($30,466)	$37,017	$1,330	Schedule 3
3	Deduct - Interest on Debt	(17,755)	(18,574)	11	(18,563)	(808)	
4	Add - O&M Savings	2,435	-	-	-	(2,435)	
5	Add- Non-Tax Ded. Expense (Net)	6,015	(6,593)	-	(6,593)	(12,608)	Schedule 34
6	Accounting Income After Tax	26,382	42,316	(30,455)	11,860	(14,521)	
7	Add (Deduct) - Timing Differences	(5,740)	(8,044)	-	(8,044)	(2,304)	Schedule 34
8	Taxable Income After Tax	$20,642	$34,272	($30,455)	3,816	($16,826)	
9		30.000%	28.500%	28.500%	28.500%	-1.500%	
10	1 - Current Income Tax Rate	70.000%	71.500%	71.500%	71.500%	1.500%	
11	Taxable Income	$29,489	$47,933	($42,595)	$5,338	($24,151)	
12	Income Tax - Current	$8,847	$13,661	($12,140)	$1,521	($7,326)	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$8,847	$13,661	($12,140)	$1,521	($7,326)	x-ref Schedules 3, 14

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Schedule 32

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Cost of Service Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return After VINGPA Adjustment	$37,017	$69,085	($18,086)	$50,999	$13,982	Schedule 4
3	Deduct - Interest on Debt	(18,563)	(26,136)	10	(26,126)	(7,563)	
4	Add - O&M Savings	-	-	-	-	-	
5	Add- Non-Tax Ded. Expense (Net)	(6,593)	(686)	-	(686)	5,908	Schedule 35
6	Accounting Income After Tax	11,860	42,263	(18,076)	24,187	12,327	
7	Add (Deduct) - Timing Differences	(8,044)	(13,552)	-	(13,552)	(5,509)	Schedule 35
8	Taxable Income After Tax	$3,816	$28,711	($18,076)	$10,635	$6,818	
9		28.500%	26.500%	26.500%	26.500%	-2.000%	
10	1 - Current Income Tax Rate	71.500%	73.500%	73.500%	73.500%	2.000%	
11	Taxable Income	$5,338	$39,062	($24,593)	$14,469	$340,924	
12	Income Tax - Current	$1,521	$10,351	($6,517)	$3,834	$2,313	
13	Income Tax - Deferred	-	-	-		-	
12	**Total Income Tax**	$1,521	$10,351	($6,517)	$3,834	$2,313	x-ref Schedules 4, 14

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS Schedule 33
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Projection	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE**				
2	Amortization of Deferred Charges	$15,557	5,949	($9,609)	Schedule 27
3	Non-tax Deductible Expenses	52	66	14	
4	Total Permanent Differences	$15,609	6,015	($9,595)	x-ref Schedule 5, 30
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$19,242	$23,798	$4,556	Schedule 27
7	Amortization of Debt Issue Expenses	2,161	26	($2,135)	
8	Transmission Pipeline Inspection Costs	-	-	$0	
9	Debt Issue Costs	(606)	(548)	58	
10	Capital Cost Allowance	(22,805)	(23,741)	(936)	Schedule 36
11	Cumulative Eligible Capital Allowance	(375)	(398)	(23)	
12	Taxable Capital Gain	-	2,859	2,859	
13	Pension & OPEB Expense Booked	2,237	2,237	-	
14	Pension & OPEB Contributions	(1,579)	(1,888)	(309)	
15	Overheads Capitalized Expensed for Tax Purposes	(1,887)	(3,460)	(1,573)	
16	Capitalized Interest	(4,766)	-	4,766	
17	Amortization/Re-amortization of Contributions in Aid of Construction	1,990	(2,545)	(4,535)	Schedule 55
18	CCA Rate Change of 2007 & 2008	-	(624)	(624)	
19	2008 Overheads Capitalized Rate Change	-	(1,455)	(1,455)	
20	Total Timing Differences	($6,388)	($5,740)	$648	x-ref Schedule 5, 30

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
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Schedule 34

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2	Amortization of Deferred Charges	$5,949	(6,660)	($12,609)	Schedule 28
3	Non-tax Deductible Expenses	66	67	1	
4	Total Permanent Differences	$6,015	($6,593)	($12,608)	x-ref Schedule 6, 31
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$23,798	$26,231	$2,433	Schedule 28
7	Amortization of Debt Issue Expenses	26	36	10	
8	Transmission Pipeline Inspection Costs	-	(590)	(590)	
9	Debt Issue Costs	(548)	(534)	14	
10	Capital Cost Allowance	(23,741)	(29,986)	(6,245)	Schedule 37
11	Cumulative Eligible Capital Allowance	(398)	(375)	23	
12	Taxable Capital Gain	2,859	856	(2,003)	
13	Pension & OPEB Expense Booked	2,237	2,345	109	
14	Pension & OPEB Contributions	(1,888)	(1,612)	276	
15	Overheads Capitalized Expensed for Tax Purposes	(3,460)	-	3,460	
16	Capitalized Interest	-	-	-	
17	Amortization of Contributions in Aid of Construction	(2,545)	(4,415)	(1,870)	Schedule 56
18	CCA Rate Change of 2007 & 2008	(624)	-	624	
19	2008 Overheads Capitalized Rate Change	(1,455)	-	1,455	
20	Total Timing Differences	($5,740)	($8,044)	($2,304)	x-ref Schedule 6, 31

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NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Forecast	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2	Amortization of Deferred Charges	($6,660)	(754)	$5,907	Schedule 29
3	Non-tax Deductible Expenses	67	68	1	
4	Total Permanent Differences	($6,593)	($686)	$5,908	x-ref Schedule 7, 32
5	**TIMING DIFFERENCE ADJUSTMENTS**				
6	Depreciation	$26,231	$30,409	4178	Schedule 29
7	Amortization of Debt Issue Expenses	36	42	6	
8	Transmission Pipeline Inspection Costs	(590)	(460)	130	
9	Debt Issue Costs	(534)	(862)	(328)	
10	Capital Cost Allowance	(29,986)	(38,743)	(8,757)	Schedule 38
11	Cumulative Eligible Capital Allowance	(375)	(352)	23	
12	Taxable Capital Gain	856	60	(797)	
13	Pension & OPEB Expense Booked	2,345	2,438	93	
14	Pension & OPEB Contributions	(1,612)	(1,661)	(49)	
15	Overheads Capitalized Expensed for Tax Purposes	-	-	-	
16	Capitalized Interest	-	-	-	
17	Amortization of Contributions in Aid of Construction	(4,415)	(4,423)	(8)	Schedule 57
18	CCA Rate Change of 2007 & 2008	-	-	-	
19	2008 Overheads Capitalized Rate Change	-	-	-	
20	Total Timing Differences	($8,044)	($13,552)	($5,509)	x-ref Schedule 7, 32

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CAPITAL COST ALLOWANCE Schedule 36
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Class	CCA Rate %	12/31/2008 UCC Balance	Adjustments	2009 Net Additions	2009 CCA	12/31/2009 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$307,018	$0	$0	($12,281)	$294,737	
2	1.3	6%	$4,728	(70)	269	(288)	4,639	
3	2	6%	$7,570	-	-	(454)	7,116	
4	3	5%	$150	-	-	(8)	142	
5	6	10%	$7	-	-	(1)	6	
6	7	15%	$15,874	235	3,752	(2,698)	17,163	
7	8	20%	$8,153	(19)	683	(1,695)	7,122	
8	9	25%	$0	-	-	-	-	
9	10	30%	$2,034	(25)	630	(697)	1,942	
10	12	100%	$520	(20)	1,988	(1,494)	994	
11	13	17%	$137	-	40	(39)	138	
12	14	5%	$350	-	-	(25)	325	
13	14	20%	($0)	-	-	-	-	
14	38	30%	$246	(3)	148	(95)	296	
15	45	45%	$235	-	-	(106)	129	
16	47	8%	$0	-	-	-	-	
17	49	8%	$5,888	89	28,207	(1,606)	32,578	
18	50	55%	$418	(58)	-	(198)	162	
19	51	6%	$26,529	1,205	13,052	(2,056)	38,730	
20		Total	$379,857	$1,334	$48,769	($23,741)	$406,219	x-ref Schedule 33

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
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CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$294,737	$0	$0	($11,789)	$282,948	
2	1.3	6%	4,639	1	210	(285)	4,565	
3	2	6%	7,116	-	-	(427)	6,689	
4	3	5%	142	1	-	(7)	136	
5	6	10%	6	-	-	(1)	5	
6	7	15%	17,163	1	1,984	(2,723)	16,425	
7	8	20%	7,122	-	893	(1,514)	6,501	
8	10	25%	-	-	-	-	-	
9	12	30%	1,942	(1)	630	(677)	1,894	
10	13	100%	994	-	1,500	(1,744)	750	
11	14	17%	138	-	30	(28)	140	
12	17	5%	325	-	-	(25)	300	
13	38	20%	-	-	-	-	-	
14	39	30%	296	-	186	(117)	365	
15	45	45%	129	-	-	(58)	71	
16	47	8%	-	-	79,145	(4,957)	74,188	
17	49	8%	32,578	-	3,639	(2,752)	33,465	
18	50	55%	162	-	-	(89)	73	
19	51	6%	38,730	-	15,649	(2,793)	51,586	
20		Total	$406,219	$2	$103,866	($29,986)	$480,101	x-ref Schedule 34

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 38

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	1	4%	$282,948	$0	$0	($11,318)	$271,630	
2	1.3	6%	4,565	-	4,980	(423)	9,122	
3	2	6%	6,689	-	-	(401)	6,288	
4	3	5%	136	-	-	(7)	129	
5	6	10%	5	1	-	(1)	5	
6	7	15%	16,425	(1)	10,449	(3,247)	23,626	
7	8	20%	6,501	-	888	(1,389)	6,000	
8	10	25%	-	-	-	-	-	
9	12	30%	1,894	1	560	(652)	1,803	
10	13	100%	750	-	1,500	(1,500)	750	
11	14	17%	140	(1)	40	(31)	148	
12	17	5%	300	-	-	(25)	275	
13	38	20%	-	-	-	-	-	
14	39	30%	365	-	154	(133)	386	
15	45	45%	71	-	-	(32)	39	
16	47	8%	74,188	1	97,626	(12,599)	159,216	
17	49	8%	33,465	-	16,565	(3,340)	46,690	
18	50	55%	73	-	-	(40)	33	
19	51	6%	51,586	(1)	17,007	(3,605)	64,987	
20		Total	$480,101	$0	$149,769	($38,743)	$591,127	x-ref Schedule 35

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 39

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Adjustments	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$737,301	$733,157	$0	$733,157	($4,144)	Schedule 44
2	Adjustment*		208,237	0	208,237	208,237	
3	Gas Plant in Service, Ending	785,862	1,012,319	0	1,012,319	226,458	Schedule 44
4	Accumulated Depreciation Beginning - Plant	(178,559)	(178,029)	0	(178,029)	530	Schedule 50
5	Adjustment*		(45,847)	0	(45,847)	(45,847)	
6	Accumulated Depreciation Ending - Plant	(196,352)	(245,154)	0	(245,154)	(48,802)	Schedule 50
					0		
7	CIAC, Beginning	(60,835)	(60,835)	0	(60,835)	(0)	Schedule 55
8	Adjustment*		(208,237)	0	(208,237)	(208,237)	
9	CIAC, Ending	(53,475)	(278,861)	0	(278,861)	(225,386)	Schedule 55
10	Accumulated Amortization Beginning - CIAC	1,990	1,990	0	1,990	(0)	Schedule 55
11	Adjustment*		45,847	0	45,847	45,847	
12	Accumulated Amortization Ending - CIAC	0	50,380	0	50,380	50,380	Schedule 55
13	Net Plant in Service, Mid-Year	$517,966	$517,483	$0	$517,483	($482)	
14	Adjustment to 13-Month Average	817	6,489	0	6,489	5,672	
15	Allocated Common Plant to TGW, Mid-Year	(104)	(104)	0	(104)	0	
16	Work in Progress, No AFUDC	1,812	3,652	0	3,652	1,840	
17	Unamortized Deferred Charges	6,246	3,689	0	3,689	(2,557)	Schedule 58
18	Cash Working Capital	(2,100)	(2,589)	(407)	(2,996)	(895)	Schedule 61
19	Other Working Capital (incl. Construction Advances)	14,889	11,575	0	11,575	(3,313)	Schedule 61
20	Future Income Taxes Regulatory Asset		58,802	0	58,802	58,802	Schedule 67
21	Future Income Taxes Liability		(58,802)	0	(58,802)	(58,802)	Schedule 67
22	**Utility Rate Base**	$539,525	$540,195	($407)	$539,788	$264	x-ref Schedule 68

*Adjustment to remove CIAC from Gas Plant in Service, and Accumulated Amortization of CIAC from Accumulated Depreciaton

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UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	2009 PROJECTION	2010 Approved Rates	2010 Adjustments	2010 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$733,157	$1,012,319	$0	$1,012,319	$279,162	Schedule 46
2	Adjustment	208,237					
3	Gas Plant in Service, Ending	1,012,319	1,036,234	0	1,036,234	23,915	
4	Accumulated Depreciation Beginning - Plant	(178,029)	(245,154)	0	(245,154)	(67,125)	Schedule 52
5	Adjustment*	(45,847)	(1,379)		(1,379)		
6	Accumulated Depreciation Ending - Plant	(245,154)	(270,987)	0	(270,987)	(25,833)	
7	CIAC, Beginning	(60,835)	(278,861)	0	(278,861)	(218,026)	Schedule 56
8	Adjustment	(208,237)					
9	CIAC, Ending	(278,861)	(275,728)	0	(275,728)	3,133	
10	Accumulated Amortization Beginning - CIAC	1,990	50,380	0	50,380	48,390	Schedule 56
11	Adjustment	45,847					
12	Accumulated Amortization Ending - CIAC	50,380	54,795	0	54,795	4,415	
13	Net Plant in Service, Mid-Year	$517,483	$540,809	$0	$540,809	$24,016	
14	Adjustment to 13-Month Average	6,489	0	0	0	(6,489)	
15	Allocated Common Plant to TGW, Mid-Year	(104)	0	0	0	104	
16	Work in Progress, No AFUDC	3,652	3,608	0	3,608	(44)	
17	Unamortized Deferred Charges	3,689	495	0	495	(3,194)	Schedule 59
18	Cash Working Capital	(2,996)	318	(750)	(432)	2,563	Schedule 62
19	Other Working Capital (incl. Construction Advances)	11,575	9,533	0	9,533	(2,043)	Schedule 62
20	Future Income Taxes Regulatory Asset	58,802	60,101	0	60,101	1,298	Schedule 67
21	Future Income Taxes Liability	(58,802)	(60,101)	0	(60,101)	(1,298)	Schedule 67
22	**Utility Rate Base**	$539,788	$554,763	($750)	$554,013	$14,914	x-ref Schedule 69

*Adjustment relates to transfer of accumulated loss on General Plant to IFRS Transitional Adjustments deferral account

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
UTILITY RATE BASE Schedule 41
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Adjustments	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$1,012,319	$1,036,234	$0	$1,036,234	$23,915	Schedule 48
2	Adjustment	0					
3	Gas Plant in Service, Ending	1,036,234	1,274,815	0	1,274,815	238,581	
4	Accumulated Depreciation Beginning - Plant	(245,154)	(270,987)	0	(270,987)	(25,833)	Schedule 54
5	Adjustment	(1,379)					
6	Accumulated Depreciation Ending - Plant	(270,987)	(299,264)	0	(299,264)	(28,277)	
7	CIAC, Beginning	(278,861)	(275,728)	0	(275,728)	3,133	Schedule 57
8	Adjustment	0					
9	CIAC, Ending	(275,728)	(276,176)	0	(276,176)	(448)	
10	Accumulated Amortization Beginning - CIAC	50,380	54,795	0	54,795	4,415	Schedule 57
11	Adjustment	0					
12	Accumulated Amortization Ending - CIAC	54,795	59,218	0	59,218	4,423	
13	Net Plant in Service, Mid-Year	$540,809	$651,454	$0	$651,454	$109,955	
14	Adjustment to 13-Month Average	0	56,712	0	56,712	56,712	
15	Allocated Common Plant to TGW, Mid-Year	0	0	0	0	0	
16	Work in Progress, No AFUDC	3,608	3,608	0	3,608	0	
17	Unamortized Deferred Charges	495	4,908	0	4,908	4,413	Schedule 60
18	Cash Working Capital	(432)	516	(381)	135	567	Schedule 63
19	Other Working Capital (incl. Construction Advances)	9,533	12,178	0	12,178	2,645	Schedule 63
20	Future Income Taxes Regulatory Asset	60,101	63,889	0	63,889	3,788	Schedule 67
21	Future Income Taxes Liability	(60,101)	(63,889)	0	(63,889)	(3,788)	Schedule 67
22	**Utility Rate Base**	$554,013	$729,375	($381)	$728,994	$174,292	x-ref Schedule 70

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 42

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011
	(1)	(3)	(4)	(5)
1	**CAPITAL EXPENDITURES**			
2	Regular Capital Expenditures	$24,036	$21,669	$25,827
3	Special Projects - CPCN's			
4	Squamish to Whistler Natural Gas Pipeline	$ 5,386	$ -	$ -
5	Mt. Hayes LNG Facility	62,986	57,216	26,709
6	CIS CCE	840	5,580	6,490
7	Garbaly	-	5,200	3,300
8	Total CPCN's	$ 69,212	$ 67,996	$ 36,499
9	TOTAL CAPITAL EXPENDITURES	$ 93,247	$ 89,665	$ 62,326
10	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
11	Regular Capital			
12	Base Capital Expenditures	$ 24,036	$ 21,669	$ 25,827
13	Add - Opening WIP	6,305	6,305	6,305
14	Less - Closing WIP	(6,305)	(6,305)	(6,305)
15	Add - AFUDC	68	52	69
16	Add - Overhead Capitalized	5,033	4,372	4,567
		Schedule 44	Schedule 46	Schedule 48
17	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 29,136	$ 26,093	$ 30,463
18	Special Projects - CPCN's			
19	CPCN Expenditures	$ 69,212	$ 67,996	$ 36,499
20	Add - Opening WIP	84,881	115,759	192,949
21	Less - Closing WIP	(115,759)	(192,949)	(22,868)
22	Add - AFUDC	5,633	9,194	4,068
23	TOTAL CPCN ADDITIONS TO GAS PLANT IN SERVICE	$ 43,966	$ 0	$ 210,648
		Schedule 44	Schedule 46	Schedule 48

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
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Schedule 43

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Opening Adjustments	CPCN'S	2009 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	-	1,194
5	441-00 Land Rights	-	-	-	-	-	-	-
6	461-00 Land Rights - Transmission	-	6,802	-	75	-	-	6,877
7	471-00 Land Rights - Distribution	-	1,830	-	85	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	-	14,947	-	2,000	(47)	-	16,900
10	402-00 Application Software - 5 year life	-	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	1,384	25,233	-	2,160	(47)	-	28,730
12	**MANUFACTURED GAS / LOCAL STORAGE**							
13	430 Manufact'd Gas - Land	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-	-
25	- Piping	-	-	-	-	-	-	-
26	- Pre-treatment	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	-	-	-	-	-	-
28	- Send out Equipment	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	-	-	-	-	-	-
30	- Control Room	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**							
34	460-00 Land in Fee Simple	2,842	-	-	-	-	-	2,842
35	461-00 Land Rights	6,802	(6,802)	-	-	-	-	-
36	462-00 Compressor Structures	10,446	819	-	-	-	-	11,265
37	463-00 Measuring Structures	6,449	1,257	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	-	130
39	465-00 Mains	223,423	99,338	43,669	4,018	-	-	370,448
40	465-00 Mains - Inspection	-	-	-	-	-	-	-
41	466-00 Compressor Equipment	50,252	6,947	-	4,589	-	-	61,788
42	466-00 Compressor Equipment - Compressor Overhaul	-	-	-	-	-	-	-
43	466-00 Compressor Equipment - Gas Turbine Overhaul	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	10,735	3,698	297	127	-	-	14,857
45	467-10 Telemetering	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	2,376	890	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	313,455	106,147	43,966	8,734	-	-	472,302

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Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Opening Adjustments	CPCN'S	2009 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**DISTRIBUTION PLANT**							
2	470-00 Land in Fee Simple	$799	$0	$0	$83	$0	$0	$882
3	471-00 Land Rights	$1,830	($1,830)	$0	$0	$0	$0	$0
4	472-00 Structures & Improvements	1,465	666	-	-	-	-	2,131
5	473-00 Services	131,548	26,273	-	8,330	(417)	-	165,734
6	474-00 House Regulators & Meter Installations	16,970	2,809	-	994	(50)	-	20,723
7	475-00 Mains	208,940	61,534	-	5,773	(289)	-	275,958
8	476-00 Compressor Equipment	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating Equipment	5,000	2,146	-	513	-	-	7,659
10	477-00 Telemetering	-	-	-	-	-	-	-
12	478-00 Meters	11,122	1,861	-	788	(39)	-	13,732
13	479-00 Other Distribution Equipment	-	-	-	-	-	-	-
14	TOTAL DISTRIBUTION PLANT	377,674	93,459	-	16,481	(795)	-	486,819
15	**GENERAL PLANT & EQUIPMENT**							
16	480-00 Land in Fee Simple	1,065	-	-	-	-	-	1,065
17	481-00 Land Rights	-	-	-	-	-	-	-
18	482-00 Structures & Improvements	-	-	-	-	-	-	-
19	- Frame Buildings	4,343	-	-	260	-	-	4,603
20	- Masonry Buildings	-	-	-	-	-	-	-
21	- Leasehold Improvement	1,344	-	-	40	(964)	-	420
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-	-
23	- Furniture & Equipment	2,424	-	-	97	-	-	2,521
24	- Computer Hardware	2,265	-	-	-	-	-	2,265
25	- Computer Software (Infrastructure)	15,907	(15,907)	-	-	-	-	-
26	- Computer Software (Non-Infrastructure)	906	(695)	-	-	-	-	211
27	484-00 Transportation Equipment	4,593	-	-	630	-	-	5,223
28	485-00 Heavy Work Equipment	786	-	-	148	-	-	934
29	486-00 Small Tools & Equipment	5,888	-	-	506	-	-	6,394
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-
33	- Telephone	1,123	-	-	80	(371)	-	832
34	- Radio	-	-	-	-	-	-	-
35	489-00 Other General Equipment	-	-	-	-	-	-	-
36	TOTAL GENERAL PLANT	40,644	(16,602)	-	1,761	(1,335)	-	24,468
37	**UNCLASSIFIED PLANT**							
38	499 Plant Suspense	-	-	-	-	-	-	-
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-
40	TOTAL	$733,157	$208,237	$43,966	$29,136	($2,177)	$0	$1,012,319 x-ref Schedules 8, 39, 42

TERASEN GAS (VANCOUVER ISLAND) INC.

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Tab 13
Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**INTANGIBLE PLANT**						
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	1,194
5	441-00 Land Rights	-	-	-	-	-	-
6	461-00 Land Rights - Transmission	6,877	-	77	-	-	6,954
7	471-00 Land Rights - Distribution	1,915	-	-	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	16,900	-	1,509	(91)	-	18,318
10	402-00 Application Software - 5 year life	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	28,730	-	1,586	(91)	-	30,225
12	**MANUFACTURED GAS / LOCAL STORAGE**						
13	430 Manufact'd Gas - Land	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	-	-	-	-	-
20	442 Structures & Improvements	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	-	-	-	-	-
22	446 Compressor Equipment	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-
25	- Piping	-	-	-	-	-	-
26	- Pre-treatment	-	-	-	-	-	-
27	- Liquefaction Equipment	-	-	-	-	-	-
28	- Send out Equipment	-	-	-	-	-	-
29	- Sub-station and Electric	-	-	-	-	-	-
30	- Control Room	-	-	-	-	-	-
31	449 Local Storage Equipment	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	-	-	-	-	-
33	**TRANSMISSION PLANT**						
34	460-00 Land in Fee Simple	2,842	-	-	-	-	2,842
35	461-00 Land Rights	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	-	-	-	-	11,265
37	463-00 Measuring Structures	7,706	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	130
39	465-00 Mains	370,448	-	3,527	-	(1,630)	372,345
40	465-00 Mains - Inspection	-	-	744	-	1,630	2,374
41	466-00 Compressor Equipment	61,788	-	731	-	(3,882)	58,637
42	466-00 Compressor Equipment - Compressor Overhaul	-	-	-	-	933	933
43	466-00 Compressor Equipment - Gas Turbine Overhaul	-	-	1,261	-	2,949	4,210
44	467-00 Measuring & Regulating Equipment	14,857	-	126	-	-	14,983
45	467-10 Telemetering	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	472,302	-	6,389	-	-	478,691

TERASEN GAS (VANCOUVER ISLAND) INC.

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Section C
Tab 13
Schedule 46

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**DISTRIBUTION PLANT**							
2	470-00 Land in Fee Simple	$882	$0	$0	$0	$0	$882	
3	471-00 Land Rights	-	-	-	-	-	-	
4	472-00 Structures & Improvements	2,131	-	-	-	-	2,131	
5	473-00 Services	165,734	-	8,168	(408)	-	173,494	
6	474-00 House Regulators & Meter Installations	20,723	-	1,275	(64)	-	21,934	
7	475-00 Mains	275,958	-	5,247	(262)	-	280,943	
8	476-00 Compressor Equipment	-	-	-	-	-	-	
9	477-00 Measuring & Regulating Equipment	7,659	-	504	-	-	8,163	
10	477-00 Telemetering	-	-	-	-	-	-	
12	478-00 Meters	13,732	-	1,016	(51)	-	14,697	
13	479-00 Other Distribution Equipment	-	-	-	-	-	-	
14	TOTAL DISTRIBUTION PLANT	486,819	-	16,210	(785)	-	502,244	
15	**GENERAL PLANT & EQUIPMENT**							
16	480-00 Land in Fee Simple	1,065	-	-	-	-	1,065	
17	481-00 Land Rights	-	-	-	-	-	-	
18	482-00 Structures & Improvements	-	-	-	-	-	-	
19	- Frame Buildings	4,603	-	167	-	-	4,770	
20	- Masonry Buildings	-	-	-	-	-	-	
21	- Leasehold Improvement	420	-	30	-	-	450	
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-	
23	- Furniture & Equipment	2,521	-	94	(897)	-	1,718	
24	- Computer Hardware	2,265	-	-	(192)	-	2,073	
25	- Computer Software (Infrastructure)	-	-	-	-	-	-	
26	- Computer Software (Non-Infrastructure)	211	-	-	-	-	211	
27	484-00 Transportation Equipment	5,223	-	630	(52)	-	5,801	
28	485-00 Heavy Work Equipment	934	-	186	-	-	1,120	
29	486-00 Small Tools & Equipment	6,394	-	516	-	-	6,910	
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	
32	488-00 Communications Equipment	-	-	-	-	-	-	
33	- Telephone	832	-	80	(160)	-	752	
34	- Radio	-	-	204	-	-	204	
35	489-00 Other General Equipment	-	-	-	-	-	-	
36	TOTAL GENERAL PLANT	24,468	-	1,907	(1,301)	-	25,074	
37	**UNCLASSIFIED PLANT**							
38	499 Plant Suspense	-	-	-	-	-	-	
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	
40	TOTAL	$1,012,319	$0	$26,092	($2,177)	$0	$1,036,234	x-ref Schedules 9, 40, 42

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Tab 13
Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**INTANGIBLE PLANT**						
2	401-00 Franchise and Consents	$190	$0	$0	$0	$0	$190
3	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	-	-	-	-	1,194
5	441-00 Land Rights	-	140	-	-	-	140
6	461-00 Land Rights - Transmission	6,954	-	78	-	-	7,032
7	471-00 Land Rights - Distribution	1,915	-	-	-	-	1,915
8	461-00 Land Rights - Whistler	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	18,318	-	1,509	(340)	-	19,487
10	402-00 Application Software - 5 year life	1,654	-	-	-	-	1,654
11	TOTAL INTANGIBLE PLANT	30,225	140	1,587	(340)	-	31,612
12	**MANUFACTURED GAS / LOCAL STORAGE**						
13	430 Manufact'd Gas - Land	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	849	-	-	-	849
20	442 Structures & Improvements	-	24,479	-	-	-	24,479
21	443 Gas Holders - Storage	-	55,956	-	-	-	55,956
22	446 Compressor Equipment	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	-	-	-	-	-
24	448 Purification Equipment	-	-	-	-	-	-
25	- Piping	-	16,635	-	-	-	16,635
26	- Pre-treatment	-	7,461	-	-	-	7,461
27	- Liquefaction Equipment	-	26,113	-	-	-	26,113
28	- Send out Equipment	-	39,169	-	-	-	39,169
29	- Sub-station and Electric	-	12,564	-	-	-	12,564
30	- Control Room	-	9,326	-	-	-	9,326
31	449 Local Storage Equipment	-	13,056	-	-	-	13,056
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-	205,608	-	-	-	205,608
33	**TRANSMISSION PLANT**						
34	460-00 Land in Fee Simple	2,842	-	-	-	-	2,842
35	461-00 Land Rights	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	-	-	-	-	11,265
37	463-00 Measuring Structures	7,706	-	-	-	-	7,706
38	464-00 Other Structures & Improvements	130	-	-	-	-	130
39	465-00 Mains	372,345	-	6,022	-	-	378,367
40	465-00 Mains - Inspection	2,374	-	560	-	-	2,934
41	466-00 Compressor Equipment	58,637	453	956	-	-	60,046
42	466-00 Compressor Equipment - Compressor Overhaul	933	-	731	-	-	1,664
43	466-00 Compressor Equipment - Gas Turbine Overhaul	4,210	-	1,218	-	-	5,428
44	467-00 Measuring & Regulating Equipment	14,983	4,447	122	-	-	19,552
45	467-10 Telemetering	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	-	-	-	-	3,266
47	469-00 Other Transmission Equipment	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	478,691	4,900	9,609	-	-	493,200

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 48

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN'S	2011 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2011	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**DISTRIBUTION PLANT**							
2	470-00 Land in Fee Simple	$882	$0	$0	$0	$0	$882	
3	471-00 Land Rights	-	-	-	-	-	-	
4	472-00 Structures & Improvements	2,131	-	-	-	-	2,131	
5	473-00 Services	173,494	-	8,517	(426)	-	181,585	
6	474-00 House Regulators & Meter Installations	21,934	-	1,259	(63)	-	23,130	
7	475-00 Mains	280,943	-	6,422	(321)	-	287,044	
8	476-00 Compressor Equipment	-	-	-	-	-	-	
9	477-00 Measuring & Regulating Equipment	8,163	-	390	-	-	8,553	
10	477-00 Telemetering	-	-	-	-	-	-	
12	478-00 Meters	14,697	-	1,039	(52)	-	15,684	
13	479-00 Other Distribution Equipment	-	-	-	-	-	-	
14	TOTAL DISTRIBUTION PLANT	502,244	-	17,627	(862)	-	519,009	
15	**GENERAL PLANT & EQUIPMENT**							
16	480-00 Land in Fee Simple	1,065	-	-	-	-	1,065	
17	481-00 Land Rights	-	-	-	-	-	-	
18	482-00 Structures & Improvements	-	-	-	-	-	-	
19	- Frame Buildings	4,770	-	-	-	-	4,770	
20	- Masonry Buildings	-	-	-	-	-	-	
21	- Leasehold Improvement	450	-	40	-	-	490	
22	483-00 Office Furniture and Equipment	-	-	-	-	-	-	
23	- Furniture & Equipment	1,718	-	101	(729)	-	1,090	
24	- Computer Hardware	2,073	-	-	(175)	-	1,898	
25	- Computer Software (Infrastructure)	-	-	-	-	-	-	
26	- Computer Software (Non-Infrastructure)	211	-	-	-	-	211	
27	484-00 Transportation Equipment	5,801	-	560	(162)	-	6,199	
28	485-00 Heavy Work Equipment	1,120	-	154	(32)	-	1,242	
29	486-00 Small Tools & Equipment	6,910	-	457	(210)	-	7,157	
30	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	
32	488-00 Communications Equipment	-	-	-	-	-	-	
33	- Telephone	752	-	80	(22)	-	810	
34	- Radio	204	-	250	-	-	454	
35	489-00 Other General Equipment	-	-	-	-	-	-	
36	TOTAL GENERAL PLANT	25,074	-	1,642	(1,330)	-	25,386	
37	**UNCLASSIFIED PLANT**							
38	499 Plant Suspense	-	-	-	-	-	-	
39	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	
40	TOTAL	$1,036,234	$210,648	$30,465	($2,532)	$0	$1,274,815	x-ref Schedules 10, 40, 42

TERASEN GAS (VANCOUVER ISLAND) INC.

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Account	Jan.1 GPIS for Depreciation	Annual Depreciation Rate %	Provision 2009 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2008	Accumulated Opening Adjustment	Accumulated 12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**INTANGIBLE PLANT**										
2	401-00 Franchise and Consents	190	3.04%	$6	$0	$0	$0	$0	$56	$0	$62
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	6.21%	74	-	-	-	-	490	-	564
4	441-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,802	1.33%	90	-	-	-	-	-	1,100	1,190
6	471-00 Land Rights - Distribution	1,830	1.36%	25	-	-	-	-	-	236	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	14,947	12.50%	1,868	-	(47)	-	-	-	4,449	6,270
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	-	213	544
11	TOTAL INTANGIBLE PLANT	26,617		2,394	-	(47)	-	-	546	5,998	8,891
12	**MANUFACTURED GAS / LOCAL STORAGE**										
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	0.00%	-	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	0.00%	-	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-	-
25	- Piping	-	0.00%	-	-	-	-	-	-	-	-
26	- Pre-treatment	-	0.00%	-	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	0.00%	-	-	-	-	-	-	-	-
28	- Send out Equipment	-	0.00%	-	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	0.00%	-	-	-	-	-	-	-	-
30	- Control Room	-	0.00%	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-		-	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**										
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	1,100	(1,100)	-
36	462-00 Compressor Structures	11,265	3.77%	425	-	-	-	-	2,727	283	3,435
37	463-00 Measuring Structures	7,706	3.75%	289	-	-	-	-	2,058	234	2,581
38	464-00 Other Structures & Improvements	130	3.00%	4	-	-	-	-	13	-	17
39	465-00 Mains	322,761	1.97%	6,358	-	-	-	-	59,317	21,490	87,165
40	465-00 Mains - Inspection	-	0.00%	-	-	-	-	-	-	-	-
41	466-00 Compressor Equipment	57,199	3.50%	2,002	-	-	-	-	10,897	2,293	15,192
42	Compressor Equipment - Compressor Overhaul	-	0.00%	-	-	-	-	-	-	-	-
43	Compressor Equipment - Gas Turbine Overhaul	-	0.00%	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	14,433	3.11%	449	-	-	-	-	1,947	1,134	3,530
45	467-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	6.45%	211	-	-	-	-	1,006	523	1,740
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	419,602		9,738	-	-	-	-	79,065	24,857	113,660

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Account	CPCN + Jan.1 GPIS for Depreciation	Annual Depreciation Rate %	Provision 2009 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2008	Accumulated Opening Adjustment	Accumulated 12/31/2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**DISTRIBUTION PLANT**										
2	470 Land	$799	0.00%	$0	$0	$0	$0	$0	$0	$0	$0
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	236	(236)	-
4	-Frame Buildings	2,131	2.31%	49	-	-	-	-	634	189	872
5	473-00 Services	157,821	2.62%	4,135	-	(417)	(268)	-	24,334	6,109	33,893
6	474-00 House Regulator & Meter Installation	19,779	2.88%	570	-	(50)	(25)	-	4,154	807	5,456
7	475-00 Mains	270,474	1.89%	5,112	-	(289)	(50)	-	51,015	11,538	67,326
8	-All Other	-	0.00%	-	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	7,146	3.66%	262	-	-	-	-	1,881	680	2,823
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
11	478 Meters	12,983	3.08%	400	-	(39)	-	-	3,030	567	3,958
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	-
13	TOTAL DISTRIBUTION PLANT	471,133		10,528	-	(795)	(343)	-	85,284	19,654	114,328
14	**GENERAL PLANT & EQUIPMENT**										
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
18	- Frame Buildings	4,343	2.44%	106	-	-	-	-	926	-	1,032
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-	-
20	- Leasehold Improvement	1,344	6.07%	82	-	(964)	-	-	(194)	-	(1,076)
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-	-
22	- Furniture & Equipment	2,424	5.00%	121	-	-	-	-	1,742	-	1,863
23	- Computer Hardware	2,265	5.99%	136	-	-	-	-	782	-	918
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	4,661	(4,661)	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	24	(1)	65
26	484-00 Transportation Equipment	4,593	5.03%	231	-	-	-	-	1,413	-	1,644
27	485-00 Heavy Work Equipment	786	5.34%	42	-	-	-	-	136	-	178
28	486-00 Small Tools & Equipment	5,888	4.85%	286	-	-	-	-	2,862	-	3,148
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	- Telephone	1,123	8.21%	92	-	(371)	-	-	782	-	503
33	- Radio	-	0.00%	-	-	-	-	-	-	-	-
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	24,042		1,138	-	(1,335)	-	-	13,134	(4,662)	8,275
36	**UNCLASSIFIED PLANT**										
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-	-
39	TOTAL	941,394		23,798	-	(2,177)	(343)	-	178,029	45,847	245,154
										x-ref Schedules 8, 39	
40	Less: Vehicle Depreciation allocated to Capital Projects			-							
41	Net Depreciation Expense			$23,798	x-ref Schedule 27					100%	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	13 mo. Avg 2010 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision: 2010 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Provision: Proceeds on Disposal	Accumulated: 12/31/2009	Accumulated: Opening Adjustment	Accumulated: 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(10)
1	**INTANGIBLE PLANT**										
2	401-00 Franchise and Consents	190	3.13%	$6	$0	$0	$0	$0	$62	$0	68
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	2.30%	27	-	-	-	-	564	-	591
4	441-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,916	0.00%	-	-	-	-	-	1,190	-	1,190
6	471-00 Land Rights - Distribution	1,915	0.00%	-	-	-	-	-	261	-	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	17,609	12.50%	2,201	-	(91)	-	-	6,270	-	8,380
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	544	-	875
11	TOTAL INTANGIBLE PLANT	29,478		2,565	-	(91)	-	-	8,891	-	11,365
12	**MANUFACTURED GAS / LOCAL STORAGE**										
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	-	0.00%	-	-	-	-	-	-	-	-
20	442 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
21	443 Gas Holders - Storage	-	0.00%	-	-	-	-	-	-	-	-
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-	-
25	- Piping	-	0.00%	-	-	-	-	-	-	-	-
26	- Pre-treatment	-	0.00%	-	-	-	-	-	-	-	-
27	- Liquefaction Equipment	-	0.00%	-	-	-	-	-	-	-	-
28	- Send out Equipment	-	0.00%	-	-	-	-	-	-	-	-
29	- Sub-station and Electric	-	0.00%	-	-	-	-	-	-	-	-
30	- Control Room	-	0.00%	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	-		-	-	-	-	-	-	-	-
33	**TRANSMISSION PLANT**										
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	3.72%	419	-	-	-	-	3,435	-	3,854
37	463-00 Measuring Structures	7,706	2.87%	221	-	-	-	-	2,581	-	2,802
38	464-00 Other Structures & Improvements	130	2.87%	4	-	-	-	-	17	-	21
39	465-00 Mains	371,397	1.73%	6,425	-	-	-	-	87,165	-	93,591
40	465-00 Mains - Inspection	1,187	0.00%	316	-	-	-	-	-	-	316
41	466-00 Compressor Equipment	60,213	3.19%	1,921	-	-	-	-	15,192	-	17,113
42	Compressor Equipment - Compressor Overhaul	467	0.00%	613	-	-	-	-	-	-	613
43	Compressor Equipment - Gas Turbine Overhaul	2,105	0.00%	1,095	-	-	-	-	-	-	1,095
44	467-00 Measuring & Regulating Equipment	14,920	5.59%	834	-	-	-	-	3,530	-	4,364
45	467-10 Telemetering	-	5.59%	-	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	10.07%	329	-	-	-	-	1,740	-	2,069
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	475,498		12,178	-	-	-	-	113,660	-	125,838

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 52

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account (1)	13 mo. Avg 2010 GPIS Balance for Depreciation (2)	Annual Depreciation Rate % (3)	Provision: 2010 (Cr.) (4)	Provision: Adjust-ments (5)	Provision: Retirements (6)	Provision: Retirement Costs (7)	Provision: Proceeds on Disposal (8)	Accumulated: 12/31/2009 (9)	Accumulated: Opening Adjustment (10)	Accumulated: 12/31/2010 (10)
1	**DISTRIBUTION PLANT**										
2	470 Land	$882	0.00%	$0	$0	$0	$0	$0	$0	$0	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
4	-Frame Buildings	2,131	3.21%	68	-	-	-	-	872	-	940
5	473-00 Services	169,614	1.91%	3,240	-	(408)	-	-	33,893	-	36,725
6	474-00 House Regulator & Meter Installation	21,329	3.45%	736	-	(64)	-	-	5,456	-	6,128
7	475-00 Mains	278,451	1.62%	4,511	-	(262)	-	-	67,326	-	71,575
8	-All Other	-	0.00%	-	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	7,911	4.60%	364	-	-	-	-	2,823	-	3,187
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-	-
11	478 Meters	14,215	4.37%	621	-	(51)	-	-	3,958	-	4,528
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	-
13		494,533		9,540	-	(785)	-	-	114,328	-	123,083
14	**GENERAL PLANT & EQUIPMENT**										
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-	-
18	- Frame Buildings	4,687	4.36%	204	-	-	-	-	1,032	(381)	855
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-	-
20	- Leasehold Improvement	435	17.86%	78	-	-	-	-	(1,076)	1,224	226
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-	-
22	- Furniture & Equipment	2,120	6.55%	139	-	(897)	-	-	1,863	427	1,532
23	- Computer Hardware	2,169	20.00%	434	-	(192)	-	-	918	385	1,545
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	-	-	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	65	-	107
26	484-00 Transportation Equipment	5,512	17.88%	986	-	(52)	-	-	1,644	(362)	2,216
27	485-00 Heavy Work Equipment	1,027	7.03%	72	-	-	-	-	178	70	320
28	486-00 Small Tools & Equipment	6,652	5.00%	333	-	-	-	-	3,148	16	3,497
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-	-
32	- Telephone	792	6.67%	53	-	(160)	-	-	503	-	396
33	- Radio	102	6.67%	7	-	-	-	-	-	-	7
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	24,772		2,348	-	(1,301)	-	-	8,275	1,379	10,701
0											
36	**UNCLASSIFIED PLANT**										
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-	-
39	TOTAL	1,024,281		26,631	-	(2,177)	-	-	245,154	1,379	270,987
											x-ref Schedules 9, 40
40	Less: Vehicle Depreciation allocated to Capital Projects			(400)							
41	Net Depreciation Expense			$26,231	x-ref Schedule 28						

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	13 mo. Avg 2011 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	401-00 Franchise and Consents	190	3.13%	$6	$0	$0	$0	$0	$68	$74
3	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-
4	402-00 Other Intangible Plant	1,194	2.30%	27	-	-	-	-	591	618
4	441-00 Land Rights	70	0.00%	-	-	-	-	-	-	-
5	461-00 Land Rights - Transmission	6,993	0.00%	-	-	-	-	-	1,190	1,190
6	471-00 Land Rights - Distribution	1,915	0.00%	-	-	-	-	-	261	261
8	461-00 Land Rights - Whistler	-	0.00%	-	-	-	-	-	-	-
9	402-00 Application Software - 8 year life	18,903	12.50%	2,363	-	(340)	-	-	8,380	10,403
10	402-00 Application Software - 5 year life	1,654	20.00%	331	-	-	-	-	875	1,206
11	TOTAL INTANGIBLE PLANT	30,919		2,727	-	(340)	-	-	11,365	13,752
12	**MANUFACTURED GAS / LOCAL STORAGE**									
13	430 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-	-	-
14	432 Manufact'd Gas - Struct. & Improvements	-	0.00%	-	-	-	-	-	-	-
15	433 Manufact'd Gas - Equipment	-	0.00%	-	-	-	-	-	-	-
16	434 Manufact'd Gas - Gas Holders	-	0.00%	-	-	-	-	-	-	-
17	436 Manufact'd Gas - Compressor Equipment	-	0.00%	-	-	-	-	-	-	-
18	437 Manufact'd Gas - Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-
19	440/441 Land in Fee Simple and Land Rights	659	0.00%	-	-	-	-	-	-	-
20	442 Structures & Improvements	18,992	6.00%	734	-	-	-	-	-	734
21	443 Gas Holders - Storage	43,412	2.51%	701	-	-	-	-	-	701
22	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-	-
23	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-	-
24	448 Purification Equipment	-	0.00%	-	-	-	-	-	-	-
25	- Piping	12,906	3.75%	312	-	-	-	-	-	312
26	- Pre-treatment	5,789	6.00%	224	-	-	-	-	-	224
27	- Liquefaction Equipment	20,260	3.75%	490	-	-	-	-	-	490
28	- Send out Equipment	30,389	3.75%	734	-	-	-	-	-	734
29	- Sub-station and Electric	9,747	3.75%	236	-	-	-	-	-	236
30	- Control Room	7,235	10.01%	467	-	-	-	-	-	467
31	449 Local Storage Equipment	10,129	4.29%	280	-	-	-	-	-	280
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	159,519		4,177	-	-	-	-	-	4,177
33	**TRANSMISSION PLANT**									
34	460-00 Land in Fee Simple	2,842	0.00%	-	-	-	-	-	-	-
35	461-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
36	462-00 Compressor Structures	11,265	3.72%	419	-	-	-	-	3,854	4,273
37	463-00 Measuring Structures	7,706	2.87%	221	-	-	-	-	2,802	3,023
38	464-00 Other Structures & Improvements	130	2.87%	4	-	-	-	-	21	25
39	465-00 Mains	375,356	1.73%	6,494	-	-	-	-	93,591	100,085
40	465-00 Mains - Inspection	2,654	9.70%	257	-	-	-	-	316	573
41	466-00 Compressor Equipment	59,342	3.20%	1,899	-	-	-	-	17,113	19,012
42	Compressor Equipment - Compressor Overhaul	1,299	12.03%	156	-	-	-	-	613	769
43	Compressor Equipment - Gas Turbine Overhaul	4,819	16.91%	815	-	-	-	-	1,095	1,910
44	467-00 Measuring & Regulating Equipment	17,268	5.95%	1,027	-	-	-	-	4,364	5,391
45	467-10 Telemetering	-	0.00%	-	-	-	-	-	-	-
46	468-00 Communication Structures & Equipment	3,266	10.07%	329	-	-	-	-	2,069	2,398
47	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-	-
48	TOTAL TRANSMISSION PLANT	485,947		11,621	-	-	-	-	125,838	137,459

TERASEN GAS (VANCOUVER ISLAND) INC.

Nov. 5 2009 NSP Agreement

Section C
Tab 13
Schedule 54

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	13 mo. Avg 2011 GPIS Balance for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**DISTRIBUTION PLANT**									
2	470 Land	$882	0.00%	$0	$0	$0	$0	$0	$0	$0
3	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
4	-Frame Buildings	2,131	3.21%	68	-	-	-	-	940	1,008
5	473-00 Services	177,540	1.91%	3,391	-	(426)	-	-	36,725	39,690
6	474-00 House Regulator & Meter Installation	22,532	3.45%	777	-	(63)	-	-	6,128	6,842
7	475-00 Mains	283,994	1.62%	4,601	-	(321)	-	-	71,575	75,855
8	-All Other	-	0.00%	-	-	-	-	-	-	-
9	477-00 Measuring & Regulating	8,358	4.60%	384	-	-	-	-	3,187	3,571
10	477-10 Telemetering	-	0.00%	-	-	-	-	-	-	-
11	478 Meters	15,191	4.37%	664	-	(52)	-	-	4,528	5,140
12	479 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-
13		510,628		9,885	-	(862)	-	-	123,083	132,106
14	**GENERAL PLANT & EQUIPMENT**									
15	480-00 Land in Fee Simple	1,065	0.00%	-	-	-	-	-	-	-
16	481-00 Land Rights	-	0.00%	-	-	-	-	-	-	-
17	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-	-
18	- Frame Buildings	4,770	4.36%	208	-	-	-	-	855	1,063
19	- Masonry Buildings	-	0.00%	-	-	-	-	-	-	-
20	- Leasehold Improvement	470	16.53%	78	-	-	-	-	226	304
21	483-00 Office Furniture and Equipment	-	0.00%	-	-	-	-	-	-	-
22	- Furniture & Equipment	1,404	6.48%	91	-	(729)	-	-	1,532	894
23	- Computer Hardware	1,986	20.00%	397	-	(175)	-	-	1,545	1,767
24	- Computer Software (Infrastructure)	-	12.50%	-	-	-	-	-	-	-
25	- Computer Software (Non-Infrastructure)	211	20.00%	42	-	-	-	-	107	149
26	484-00 Transportation Equipment	6,000	17.88%	1,073	-	(162)	-	-	2,216	3,127
27	485-00 Heavy Work Equipment	1,181	7.09%	84	-	(32)	-	-	320	372
28	486-00 Small Tools & Equipment	7,034	5.00%	352	-	(210)	-	-	3,497	3,639
29	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-	-	-
30	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	-
31	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-	-
32	- Telephone	781	6.67%	52	-	(22)	-	-	396	426
33	- Radio	329	6.67%	22	-	-	-	-	7	29
34	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-	-
35	TOTAL GENERAL PLANT	25,231		2,399	-	(1,330)	-	-	10,701	11,770
36	**UNCLASSIFIED PLANT**									
37	499 Plant Suspense	-	0.00%	-	-	-	-	-	-	-
38	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-	-
39	TOTAL	1,212,244		30,809	-	(2,532)	-	-	270,987	299,264
									x-ref Schedules 10, 41	
40	Less: Vehicle Depreciation allocated to Capital Projects			(400)						
41	Net Depreciation Expense			$30,409	x-ref Schedule 29					

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	CPCN / Jan.1 Bal Adjustment	2009 Additions / Reamortization	2009 Additions	2009 Retirements / Repayment	Balance 12/31/2009	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**CIAC**							
2								
3	Distribution Contributions	$0	$95,288	$0	$892	$0	$96,180	
4								
5	Transmission Contributions	-	112,949	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	-	17,034	-	-	-	17,034	
10	Government Loans Contribution	60,835	-	-	-	(8,137)	52,698	
11								
12	TOTAL Contributions	60,835	225,271	-	892	(8,137)	278,861	x-ref Schedule 8, 39
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	-	(19,525)	(2,084)	-	-	(21,609)	
19								
20	Transmission Contributions	-	(26,320)	(2,451)	-	-	(28,771)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	-	-	-	-	-	-	
25	Government Loans Contribution	(1,990)	-	1,990	-	-	-	
26								
27	TOTAL Amortization	(1,990)	(45,845)	(2,545)	-	-	(50,380)	x-ref Schedule 8, 39
28								
29	**NET CONTRIBUTIONS**	$58,845	179,426	($2,545)	$892	($8,137)	$228,481	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line			CPCN /	2010				
		Balance	Jan.1 Bal	Additions /		Retirements /	Balance	
No.	Particulars	12/31/2009	Adjustment	Reamortization	Additions	Repayment	12/31/2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	**CIAC**							
2								
3	Distribution Contributions	$96,180	$0	$0	$442	$0	$96,622	
4								
5	Transmission Contributions	112,949	-	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	17,034	-	-	-	-	17,034	
10	Government Loans Contribution	52,698	-	-	-	(3,575)	49,123	
11								
12	TOTAL Contributions	278,861	-	-	442	(3,575)	275,728	x-ref Schedule 9, 40
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	(21,609)	-	(1,817)	-	-	(23,426)	
19								
20	Transmission Contributions	(28,771)	-	(2,303)	-	-	(31,074)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	-	-	(295)	-	-	(295)	
25	Government Loans Contribution	-	-	-	-	-	-	
26								
27	TOTAL Amortization	(50,380)	-	(4,415)	-	-	(54,795)	x-ref Schedule 9, 40
28								
29	**NET CONTRIBUTIONS**	$228,481	$0	($4,415)	$442	($3,575)	$220,933	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	CPCN / Jan.1 Bal Adjustment	2011 Additions / Reamortization	2011 Additions	2011 Retirements / Repayment	Balance 12/31/2011	
	(1)	(2)	(3)	(4)	(5)	(5)	(6)	
1	**CIAC**							
2								
3	Distribution Contributions	$96,622	$0	$0	$448	$0	$97,070	
4								
5	Transmission Contributions	112,949	-	-	-	-	112,949	
6								
7	Others	-	-	-	-	-	-	
8								
9	TGW Contribution for Whistler Pipeline	17,034	-	-	-	-	17,034	
10	Government Loans Contribution	49,123	-	-	-	-	49,123	
11								
12	TOTAL Contributions	275,728	-	-	448	-	276,176	x-ref Schedule 10, 41
13								
14								
15								
16	**Amortization**							
17								
18	Distribution Contributions	(23,426)	-	(1,825)	-	-	(25,251)	
19								
20	Transmission Contributions	(31,074)	-	(2,303)	-	-	(33,377)	
21								
22	Others	-	-	-	-	-	-	
23								
24	TGW Contribution for Whistler Pipeline	(295)	-	(295)	-	-	(590)	
25	Government Loans Contribution	-	-	-	-	-	-	
26								
27	TOTAL Amortization	(54,795)	-	(4,423)	-	-	(59,218)	x-ref Schedule 10, 41
28								
29	**NET CONTRIBUTIONS**	$220,933	$0	($4,423)	$448	$0	$216,958	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less- Taxes*	Net Additions	Amortization Expense	Balance 12/31/2009	Mid-Year Average 2009	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Gas Cost Variance Account (GCVA)	$4,162	($5,781)	$1,734	($4,047)	($4,162)	($4,047)	$58	x-ref Schedules 2, 14, 27
2	Energy Policy Related								
3	Energy Efficiency & Conservation (EEC)	-	1,379	(414)	965	-	965	483	
4	NGV Conversion Grants	-	-	-	-	-	-	-	
5	Non-Controllable Items								
6	Insurance Variance	-	51	(15)	36	(36)	(0)	-	
7	Pension Expense	-	299	-	299	(299)	-	-	
8	Olympic Security Costs	-	84	(25)	59	-	59	29	
9	IFRS Conversion Costs	11	56	(17)	39	-	50	31	
10	Cost of Current Applications								
11	2010-2011 Revenue Requirement Application	40	118	(35)	82	-	122	81	
12	2009 ROE & Cost of Capital Application	-	70	(21)	49	-	49	25	
13	CCE CPCN Application	-	30	(9)	21	-	21	11	
14	2009 Rate Design Application	-	69	(21)	48	-	48	24	
15	Other								
16	PCEC Start Up Costs	1,184	-	-	-	(44)	1,140	1,162	
17	IFRS Transitional Adjustments	-	-	-	-	-	-	-	
18	Pension & OPEB funding	-	-	-	-	-	-	-	
19	Residual Deferred Charges								
20	Compressor Fired Hours	(1,288)	(770)	231	(539)	-	(1,827)	(1,557)	
21	LNG	826	-	-	-	(415)	411	619	
22	VIGP	15	-	-	-	(7)	7	11	
23	OSC - Compliance Certification Costs	-	12	(4)	9	(9)	0	-	
24	Financing Costs	2,429	-	-	-	(240)	2,189	2,309	
25	Preliminary Survey & Investigation costs	36	0	-	0	-	36	36	
26	BC Capital Tax Assessment & Appeal Cost	737	-	-	-	(737)	-	369	
30	Total Deferred Charges for Rate Base	$8,152	($4,383)	$1,405	($2,979)	($5,949)	($775)	$3,689	x-ref Schedules 8, 39
31	Non-Rate Base Deferral Accounts								
32	RDDA	7,149	(10,211)	3,062	(7,149)	-	(0)	3,575	
33	2009 Revenue Surplus	-	(4,231)	1,269	(2,962)	-	(2,962)	(1,481)	
34	Rate Stabilization Deferral Account	-	-	-	-	-	-	-	
35	Interest Accumulated on RSDA	-	-	-	-	-	-	-	
36	Financing Costs	-	-	-	-	-	-	-	
37	Total Deferred Charges for Non-Rate Base	$7,149	($14,443)	$4,331	($10,112)	$0	($2,962)	$2,093	

38 Notes:
39 *Taxes= 30% x Gross Addition

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Adjustment	Gross Additions	Less-Taxes*	Net Additions	Amortization Expense	Balance 12/31/2010	Mid-Year Average 2010	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	Gas Cost Variance Account (GCVA)	($4,047)		$0	$0	$0	$4,047	$0	($2,023)	x-ref Schedules 3, 14, 28
2	Energy Policy Related									
3	Energy Efficiency & Conservation (EEC)	965		5,204	(1,483)	3,721	(97)	4,590	2,778	
4	NGV Conversion Grants	-		100	-	100	-	100	50	
5	Non-Controllable Items									
6	Insurance Variance	(0)		-	-	-	-	(0)	-	
7	Pension Expense	-		-	-	-	-	-	-	
8	Olympic Security Costs	59		298	(85)	213	-	272	165	
9	IFRS Conversion Costs	50		34	(10)	25	-	75	63	
10	Cost of Current Applications									
11	2010-2011 Revenue Requirement Application	122		-	-	-	(61)	61	92	
12	2009 ROE & Cost of Capital Application	49		-	-	-	(10)	39	44	
13	CCE CPCN Application	21		-	-	-	(4)	17	19	
14	2009 Rate Design Application	48		-	-	-	(24)	24	36	
15	Other									
16	PCEC Start Up Costs	1,140		-	-	-	(44)	1,096	1,118	
17	IFRS Transitional Adjustments	-	1,379	-	-	1,379	-	1,379	1,379	
18	Pension & OPEB funding	-		(5,076)	-	(5,076)	-	(5,076)	(2,538)	
19	Residual Deferred Charges									
20	Compressor Fired Hours	(1,827)		-	-	-	1,827	(0)	(913)	
21	LNG	411		-	-	-	(411)	(0)	206	
22	VIGP	7		-	-	-	(7)	-	4	
23	OSC - Compliance Certification Costs	0		-	-	-	-	0	-	
24	Financing Costs	2,189	(2,189)	-	-	(2,189)	-	-	-	
25	Preliminary Survey & Investigation costs	36		-	-	-	(36)	-	18	
26	BC Capital Tax Assessment & Appeal Cost	-		-	-	-	-	-	-	
30	Total Deferred Charges for Rate Base	($775)	($811)	$560	($1,578)	($1,828)	$5,179	$2,576	$495	x-ref Schedules 9, 40
31	Non-Rate Base Deferral Accounts									
32	RDDA	-		-	-	-	-	-	-	
33	2009 Revenue Surplus	(2,962)		-	-	-	1,481	(1,481)	(2,222)	x-ref Schedule 28
34	Rate Stabilization Deferral Account	-		(44,473)	12,140	(32,333)	-	(32,333)	(16,167)	
35	Interest Accumulated on RSDA	-		(404)	115	(289)	-	(289)	(145)	
36	Financing Costs	-	2,189	1,000	-	1,000	(250)	2,940	2,564	
37	Total Deferred Charges for Non-Rate Base	($2,962)	$2,189	($43,878)	$12,255	($31,622)	$1,231	($31,164)	($15,969)	

38 Notes:
39 *Taxes = 28.5% x Gross Addition

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less-Taxes*	Net Additions	Amortization Expense	Balance 12/31/2011	Mid-Year Average 2011	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	Gas Cost Variance Account (GCVA)	0	0	0	0	0	0	0	x-ref Schedules 4, 14, 29
2	Energy Policy Related								
3	Energy Efficiency & Conservation (EEC)	4,590	5,683	(1,506)	4,177	(469)	8,298	6,444	
4	NGV Conversion Grants	100	100	0	100	0	200	150	
5	Non-Controllable Items								
6	Insurance Variance	(0)	0	0	0	0	(0)	0	
7	Pension Expense	0	0	0	0	0	0	0	
8	Olympic Security Costs	272	0	0	0	(91)	181	226	
9	IFRS Conversion Costs	75	18	(5)	14	(25)	63	69	
10	Cost of Current Applications								
11	2010-2011 Revenue Requirement Application	61	0	0	0	(61)	0	31	
12	2009 ROE & Cost of Capital Application	39	0	0	0	(10)	29	34	
13	CCE CPCN Application	17	0	0	0	(4)	13	15	
14	2009 Rate Design Application	24	0	0	0	(24)	(0)	12	
15	Other								
16	PCEC Start Up Costs	1,096	0	0	0	(44)	1,052	1,074	
17	IFRS Transitional Adjustments	1,379	11,790	0	11,790	0	13,169	7,274	
18	Pension & OPEB funding	(5,076)	(10,689)	0	(10,689)	0	(15,765)	(10,421)	
19	Residual Deferred Charges								
20	Compressor Fired Hours	(0)	0	0	0	0	(0)	0	
21	LNG	(0)	0	0	0	0	(0)	0	
22	VIGP	0	0	0	0	0	0	0	
23	OSC - Compliance Certification Costs	0	0	0	0	0	0	0	
24	Financing Costs	0	0	0	0	0	0	0	
25	Preliminary Survey & Investigation costs	0	0	0	0	0	0	0	
26	BC Capital Tax Assessment & Appeal Cost	0	0	0	0	0	0	0	
30	Total Deferred Charges for Rate Base	$2,576	$6,902	($1,511)	$5,392	($727)	$7,240	$4,908	x-ref Schedules 10, 41
31	Non-Rate Base Deferral Accounts								
32	RDDA	0	0	0	0	0	0	0	
33	2009 Revenue Surplus	(1,481)	0	0	0	1,481	0	(741)	x-ref Schedule 29
34	Rate Stabilization Deferral Account	(32,333)	(26,471)	6,517	(18,087)	0	(50,420)	(41,377)	
35	Interest Accumulated on RSDA	(289)	(1,972)	523	(1,450)	0	(1,739)	(1,014)	
36	Financing Costs	2,940	1,000	0	1,000	(50)	3,889	3,414	
37	Total Deferred Charges for Non-Rate Base	($31,049)	($27,443)	$7,040	($18,536)	$1,431	($48,270)	($39,717)	

38 Notes:
39 *Taxes = 26.5% x Gross Addition

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Approved Rates	2009 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$5,293	$4,738	$4,331	($962)	Schedule 64
4	Customer Deposits	(2,215)	(2,191)	(2,191)	24	
6	Less - Funds Available:					
7	Reserve for Bad Debts		0	-	-	
8	Withholdings From Employees	(5,178)	(5,136)	(5,136)	42	
9	Subtotal	(2,100)	(2,589)	(2,996)	(895)	x-ref Schedules 8, 39
10	**Other Working Capital Items**					
11	Refundable Contribution	(289)	(290)	(290)	(1)	
12	Gas in Storage	14,943	11,865	11,865	(3,079)	
13	Inventory - Materials & Supplies	234	0	-	(234)	
14	Other Working Capital Items		0	0	0	
15	Subtotal	14,889	11,575	11,575	(3,313)	x-ref Schedules 8, 39
16	Total	$12,788	$8,986	$8,579	($4,209)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars (1)	2009 PROJECTION (2)	2010 Approved Rates (3)	2010 Cost of Service Rates (4)	Change (5)	Reference (6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$4,331	$2,345	$1,595	($2,736)	Schedule 64
4	Customer Deposits	(2,191)	0	-	2,191	
6	Less - Funds Available:					
7	Reserve for Bad Debts	0	(1,008)	(1,008)	(1,008)	
8	Withholdings From Employees	(5,136)	(1,019)	(1,019)	4,117	
9	Subtotal	(2,996)	318	(432)	2,563	x-ref Schedules 9, 40
10	**Other Working Capital Items**					
11	Refundable Contribution	(290)	(290)	(290)	(0)	
12	Gas in Storage	11,865	9,822	9,822	(2,043)	
13	Inventory - Materials & Supplies	0	0	-	-	
14	Other Working Capital Items	0	0	0	0	
15	Subtotal	11,575	9,533	9,533	(2,043)	x-ref Schedules 9, 40
16	Total	$8,579	$9,850	$9,100	$521	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	2010 FORECAST	2011 Approved Rates	2011 Cost of Service Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$1,595	$2,291	$1,910	$315	Schedule 64
4	Customer Deposits	0	0	-	0	
6	Less - Funds Available:					
7	Reserve for Bad Debts	(1,008)	(1,045)	(1,045)	(37)	
8	Withholdings From Employees	(1,019)	(730)	(730)	289	
9	Subtotal	(432)	516	135	567	x-ref Schedules 10, 41
10	**Other Working Capital Items**					
11	Refundable Contribution	(290)	(290)	(290)	0	
12	Gas in Storage	9,822	12,467	12,467	2,645	
13	Inventory - Materials & Supplies	0	0	0	0	
14	Other Working Capital Items	0	0	0	0	
15	Subtotal	9,533	12,178	12,178	2,645	x-ref Schedules 10, 41
16	Total	$9,100	$12,694	$12,313	$3,213	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Days	2009 Expenses	2009 Cash Working Capital	2010 Days	2010 Expenses	2010 Cash Working Capital	2011 Days	2011 Expenses	2011 Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2	Revenue Lag Days	43.8			39.7			39.8			Schedule 65
3	Expense Lead Days	33.5			34.7			35.2			Schedule 66
4	Net Lead/(Lag) Days	10.3	$167,909	$4,738	5.0	171,216	$2,345	4.6	$181,768	$2,291	
5	**CASH WORKING CAPITAL, COST OF SERVICE RATES**										
6	Revenue Lag Days	43.8			39.9			39.9			Schedule 65
7	Expense Lead Days	34.1			36.2			35.9			Schedule 66
8	Net Lead/(Lag) Days	9.7	$162,980	$4,331	3.7	$157,325	$1,595	4.0	$174,258	$1,910	Schedule 62
9	**CASH WORKING CAPITAL CHANGE**			($407)			($750)			($381)	

\# Cash working capital = Col. 2 x Col. 3 / 365 days

CASH WORKING CAPITAL
LEAD TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Revenue At Approved Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2	Gas Sales and Transportation Service Revenue										
3	Residential and Commercial	$176,878	43.8	$7,747,242	$176,746	38.7	$6,842,760	$179,702	38.7	$6,957,438	Schedules 18, 19, 20
4	Industrial (ILF & HLF)	2,624	43.8	114,918	2,699	38.4	103,658	2,699	38.4	103,658	
5	NGV Fuel - Stations	0	0.0	0	0	0.0	0	0	0.0	0	
6	T-Service	22,194	43.8	972,108	20,669	38.4	793,684	20,501	38.4	787,197	
7	Total Gas Sales	201,696	43.8	8,834,268	200,114	38.7	7,740,102	202,902	38.7	7,848,293	
8	Other Revenues										
9	Late Payment Charges	368	43.8	16,110	340	38.9	13,226	345	38.9	13,436	Schedule 22
10	Returned Cheque Charges	4	43.8	158	5	38.9	191	5	38.9	195	
11	Connection Charges	519	43.8	22,741	370	38.9	14,385	380	38.9	14,790	
12	Other Utility Income	2	43.8	105	2	38.9	93	732	38.9	28,514	
13	Royalty Revenue - For CWC Reasons	28,095	43.8	1,281,118	35,832	45.6	1,633,921	40,091	45.6	1,828,168	
14	LNG Mitigation	0	0.0	0	0	0.0	0	9,020	38.9	350,878	
15	Total Revenue	$230,684	43.8	$10,154,500	$236,663	39.7	$9,401,918	$253,475	39.8	$10,084,274	
16	**REVENUE, COST OF SERVICE RATES**										
17	Gas Sales and Transportation Service Revenue										
18	Residential and Commercial	$162,549	43.8	$7,119,633	$134,490	38.7	$5,205,395	$155,269	38.7	$6,010,520	Schedules 18, 19, 20
19	Industrial (ILF & HLF)	2,510	43.8	109,925	2,350	38.4	90,256	2,529	38.4	97,129	
20	NGV Fuel - Stations	0	0.0	0	0	0.0	0	0	0.0	0	
21	T-Service	22,194	43.8	972,108	20,669	38.4	793,684	20,501	38.4	787,197	
22	Total Gas Sales	187,253	43.8	8,201,666	157,509	38.7	6,089,335	178,299	38.7	6,894,846	
23	Other Revenues										
24	Late Payment Charges	368	43.8	16,110	340	38.9	13,226	345	38.9	13,436	Schedule 22
25	Returned Cheque Charges	4	43.8	158	5	38.9	191	5	38.9	195	
26	Connection Charges	519	43.8	22,741	370	38.9	14,385	380	38.9	14,790	
27	Other Utility Income	2	43.8	105	2	38.9	93	2	38.9	93	
28	Royalty Revenue - For CWC Reasons	28,095	43.8	1,281,118	35,832	45.6	1,633,921	40,091	45.6	1,828,168	
29	LNG Mitigation	0	0.0	0	0	0.0	0	9,020	38.9	350,878	
30	Total Revenue	$216,241	43.8	$9,521,898	$194,058	39.9	$7,751,151	$228,142	39.9	$9,102,406	

CASH WORKING CAPITAL
LAG TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2	O&M Expenses	$27,006	22.5	$607,635	$26,858	35.8	$961,516	$28,136	35.8	$1,007,255	
3	Transportation Costs	3,977	62.7	249,358	$4,015	40.2	161,403	$4,122	40.2	165,704	
4	Gas Purchases	99,314	40.5	4,022,217	98,628	40.2	3,964,846	107,311	40.2	4,313,902	
5	Taxes Other Than Income										
6	Property Taxes	8,449	3.5	29,572	9,119	2.6	23,709	9,564	2.6	24,867	
7	Carbon Tax	7,613	33.3	253,513	10,638	29.5	313,821	13,892	29.5	409,814	
8	GST - Net	2,413	50.3	121,375	2,392	39.8	95,221	2,426	39.8	96,570	
9	PST	5,959	33.3	198,435	5,905	37.1	219,076	5,965	37.1	221,302	
#	Income Tax	13,178	10.7	141,005	13,661	15.2	207,647	10,351	15.2	157,335	
#	Total	167,909	33.5	5,623,109	171,216	34.7	5,947,239	181,767	35.2	6,396,749	
#	**EXPENSES, COST OF SERVICE RATES**										
#	O&M Expenses	$27,006	22.5	$607,635	$26,858	35.8	$961,516	$28,136	35.8	$1,007,269	
#	Transportation Costs	3,977	62.7	249,358	$4,015	40.2	161,403	$4,122	40.2	165,704	
#	Gas Purchases	99,314	40.5	4,022,217	98,628	40.2	3,964,846	107,311	40.2	4,313,902	
#	Taxes Other Than Income										
#	Property Taxes	8,449	3.5	29,572	9,119	2.6	23,709	9,564	2.6	24,866	
#	Carbon Tax	7,613	33.3	253,513	10,638	29.5	313,821	13,892	29.5	409,814	
#	GST - Net	2,241	50.3	112,718	1,884	39.8	74,995	2,133	39.8	84,885	
#	PST	5,533	33.3	184,249	4,662	37.1	172,960	5,266	37.1	195,369	
#	Income Tax	8,847	10.7	94,663	1,521	15.2	23,119	3,834	15.2	58,277	
#	Total	162,980	34.1	5,553,924	157,325	36.2	5,696,370	174,258	35.9	6,260,086	

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
Tab 13
Schedule 67

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($710,651)	($776,930)	($813,945)
3	Less: Undepreciated Capital Cost	(529,801)	(587,921)	(610,463)
4		(180,850)	(189,009)	(203,482)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(45,153)	(47,255)	(50,836)
7				
8	Total FIT Liability- After Tax (PP&E)	(45,153)	(47,255)	(50,836)
9	Total FIT Liability- After Tax (Non-PP&E)	1,031	1,206	1,040
10	Total FIT Liability- After Tax	(44,121)	(46,048)	(49,795)
11				
12	Tax Gross Up	(14,681)	(15,351)	(16,583)
13				
14	FIT Liability/Asset - End of Year	(58,802)	(61,399)	(66,379)
15				
16	FIT Liability/Asset - Opening Balance	(58,802)	(58,802)	(61,399)
17				
18	FIT Liability/Asset - Mid Year	(58,802)	(60,101)	(63,889)
19		x-ref Schedules 8, 39	x-ref Schedules 9, 40	x-ref Schedules 10, 41
20				
21	Note: * Excludes Land			

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C
RETURN ON CAPITAL — Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2009 — Schedule 68
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 71		$260,940	48.300%	5.956%	2.880%	15,541	x-ref Schedule 5
3	Unfunded Debt			63,177	11.700%	1.500%	0.180%	948	x-ref Schedule 5
4	Common Equity			216,078	40.000%	13.841%	5.536%	29,907	
5	Before Sub Debt Interest	Schedule 39		$540,195	100.000%		8.596%	$46,396	
6	Sub Debt Interest							1,270	x-ref Schedule 5
7	Total						8.824%	$47,666	
8	2009 COST OF SERVICE RATES - PROJECTION								
9	Long-Term Debt			$260,940	48.340%	5.956%	2.880%	15,541	x-ref Schedule 5
10	Unfunded Debt		$63,177						
11	Adjustment, Revised Rates		(244)	62,933	11.660%	1.500%	0.170%	944	x-ref Schedule 5
12	Common Equity			215,915	40.000%	9.170%	3.670%	19,799	
13	Before Sub Debt Interest	Schedule 39		$539,788	100.000%		6.720%	$36,284	
14	Sub Debt Interest							1,270	x-ref Schedule 5
15	Total						6.957%	37,554	x-ref Schedule 2, 5, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2010 | Schedule 69
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 72		$289,659	52.210%	5.950%	3.110%	17,233	x-ref Schedule 6
3	Unfunded Debt			43,199	7.790%	2.500%	0.190%	1,080	x-ref Schedule 6
4	Common Equity			221,905	40.000%	22.882%	9.153%	50,776	
5	Before Sub Debt Interest	Schedule 40		$554,763	100.000%		12.453%	$69,089	
6	Sub Debt Interest							261	x-ref Schedule 6
7	Total						12.501%	$69,350	
8	2010 COST OF SERVICE RATES - FORECAST								
9	Long-Term Debt			$289,659	52.280%	5.950%	3.110%	17,233	x-ref Schedule 6
10	Unfunded Debt		$43,199						
11	Adjustment, Revised Rates		(450)	42,749	7.720%	2.500%	0.190%	1,069	x-ref Schedule 6
12	Common Equity			221,605	40.000%	9.170%	3.670%	20,321	
13	Before Sub Debt Interest	Schedule 40		$554,013	100.000%		6.970%	$38,623	
14	Sub Debt Interest							261	x-ref Schedule 6
15	Total						7.019%	$38,884	x-ref Schedule 3, 6, 14

TERASEN GAS (VANCOUVER ISLAND) INC. | Nov. 5 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2011 | Schedule 70
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	APPROVED RATES								
2	Long-Term Debt	Schedule 73		$390,731	53.570%	6.119%	3.278%	23,909	x-ref Schedule 7
3	Unfunded Debt			46,894	6.430%	4.750%	0.305%	2,227	x-ref Schedule 7
4	Common Equity			291,750	40.000%	15.361%	6.145%	44,816	
5	Total	Schedule 41		$729,375	100.000%		9.728%	$70,953	
6	2011 COST OF SERVICE RATES - FORECAST								
7	Long-Term Debt			$390,731	53.600%	6.119%	3.280%	23,909	x-ref Schedule 7
8	Unfunded Debt		$46,894						
9	Adjustment, Revised Rates		(229)	46,665	6.400%	4.750%	0.304%	2,217	x-ref Schedule 7
10	Common Equity			291,598	40.000%	9.170%	3.668%	26,740	
11	Total	Schedule 41		$728,994	100.000%		7.252%	52,866	x-ref Schedule 4, 7, 14

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
EMBEDDED COST OF LONG-TERM DEBT Schedule 71
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	$250,000	$15,270	
2											
3											
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	1.630%	13,381	-	13,381	2.473%	10,940	271	
5	Long Term (Rate Base) Debt				263,381	2,014	261,367		260,940	15,541	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	631	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	3,729	275	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	(0)	33	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	3,420	331	
11	Series 8 RDDA Sub Debt	1-Jun-2003	31-Jul-2008	6.300%				6.300%	-	-	
12	RDDA Subtotal								7,149	1,270	
13								Total with Sub Debt	$268,089	$16,811	x-ref Schedule 68
14								Average Embedded Cost before Sub Debt		5.956%	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
EMBEDDED COST OF LONG-TERM DEBT Schedule 72
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt 1	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	250,000	$15,270	
2	Long Term Debt 2	1-Oct-2010	1-Oct-2039	6.004%	100,000	1,000	99,000	6.078%	25,205	1,532	
3											
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	2.630%	15,526	-	15,526	2.984%	14,454	431	
5	Long Term (Rate Base) Debt				365,526	3,014	362,512		289,659	17,233	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	-	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	-	136	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	-	-	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	-	125	
11									-	-	
12	Less: RDDA Sub Debt Adjustment								-	261	
13								Total with Sub Debt	$289,659	$17,495	x-ref Schedule 69
14								Average Embedded Cost before Sub Debt		5.950%	

TERASEN GAS (VANCOUVER ISLAND) INC. — Nov. 5 2009 NSP Agreement — Section C, Tab 13, Schedule 73

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
1	Long Term Debt 1	16-Feb-2006	15-Feb-2038	6.050%	$250,000	2,014	$247,986	6.108%	$250,000	$15,270	
2	Long Term Debt 2	1-Oct-2010	1-Oct-2039	6.004%	100,000	1,000	99,000	6.078%	100,000	6,078	
3	Long Term Debt 3	1-Oct-2011	1-Oct-2041	6.892%	100,000	1,000	99,000	6.972%	25,205	1,757	
4	PCEPA Repayment Loan	1-Jan-2008	1-Jan-2013	4.880%	15,526	-	15,526	5.181%	15,526	804	
5	Long Term (Rate Base) Debt				465,526	4,014	461,512		390,731	23,909	
6	Series 1 RDDA Sub Debt	1-Jun-2006	11-Jan-2011	7.280%				7.280%	-	-	
7	Series 2 RDDA Sub Debt	1-Jun-2002	31-Jul-2012	7.370%				7.370%	-	-	
8	Series 4 RDDA Sub Debt	1-Jun-2004	14-May-2009	6.820%				6.820%	-	-	
9	Series 5 RDDA Sub Debt	1-Jun-2005	6-Jul-2010	5.950%				5.950%	-	-	
10	Series 7 RDDA Sub Debt	1-Jun-2007	26-Jun-2012	7.370%				7.370%	-	-	
11									-	-	
12	RDDA Subtotal								-	-	
13								Total with Sub Debt	$390,731	$23,909	x-ref Schedule 69
14								Average Embedded Cost before Sub Debt		6.119%	

TERASEN GAS (VANCOUVER ISLAND) INC. Nov. 5 2009 NSP Agreement Section C
Tab 13
Schedule 74

RDDA CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2007 - 2009
In Dollars

Line No.	Particulars	Approved 2007	Actual 2008	Projected 2009	Reference
	(1)	(2)	(3)	(5)	(6)
1	**Opening Balance**	$41,626,420	$ 27,907,609	$ 7,149,120	
2	Deemed Interest on Subordinated Debt	$ 3,207,564	$ 2,481,026	$ 1,269,953	
3	Annual Revenue Surplus Allocated to Sub Debt Interest Payment	(3,207,564)	(2,481,026)	(1,269,953)	
4	Annual Revenue Surplus Allocated to RDDA Amortization	(13,718,811)	(20,758,489)	(7,149,120)	*See Note
5	**Closing Balance**	$ 27,907,609	$ 7,149,120	$ -	

*2009 is projected to be the first year where the Annual Revenue Surplus is greater than the sum of the Opening Balance and the Subt Debt Interest. The remainer of the surplus not shown as allocated to either Sub Debt Interest Payment or RDDA Amortization has been allocated to the 2009 Revenue Surplus Deferral Account.

Terasen Gas (Vancouver Island) Inc. 2010-2011 Revenue Requirements Application
Negotiated Settlement Process
Issues of Particular Concern to the Commission Panel

In accordance with sections 3 and 9 of the Negotiated Settlement Process-Policy, Procedures and Guidelines, the Commission Panel has identified the following issues of particular concern that parties should be aware of during the negotiations:

1. EEC Program-TGVI is to provide results of the programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding.

2. Natural Gas for Vehicles ("NGV")-if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?

3. Biogas-could be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost.

4. International Financial Reporting Standards ("IFRS")-could have no IFRS impact in 2010.

5. 2010 Rate Changes-in the event that a 2010 rate reduction were to occur as a result of the negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability.

6. CPCN threshold-why should the threshold increase from $5 million.

7. Unrealized losses in rate base-should some of these losses be to the shareholder? Parties should present a separate settlement package.

8. Rate Design-should BC Hydro receive any refund for the expected 2009 RDDA surplus?

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Valerie Conrad 687-3017
Sarah Khan 687-4134
Eugene Kung 687-3006
James L. Quail 687-3034
Ros Salvador 488-1315
Leigha Worth 687-3044

Barristers & Solicitors

Peggy Lee
Article Student

Our file: 7430

November 12, 2009

VIA EMAIL

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Terasen Gas Vancouver Island Inc. Revenue Requirements 2010-2011 Negotiated Settlement

This is to confirm, that we are satisfied that the draft Settlement Agreement circulated by Mr. Thompson and Mr. Loski on November 5, 2009 accurately captures the consensus reached by the parties to the Negotiated Settlement Process in this proceeding, and that we have been instructed by our clients, BCOAPO et al., to endorse it.

Accordingly, we ask that the Commission incorporate it into a consent Order for the resolution of all issues in the Application.

Our only further comments, made here only "for the record" and in no way detracting from our clients' endorsement of the Settlement, concern the “Alternative Energy Solutions" addressed under heading 8 of the document. While we believe that the ultimately appropriate corporate and regulatory formats for these lines of business are subject-matters which may require eventual determination by the Commission, our clients are content with the treatment of these issues in the Settlement Agreement over its term, in that it provides a “firewall” to ensure that the utility’s natural gas distribution customers do not subsidize or otherwise contribute to these nascent programs through their rates.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in filed signed by:

Jim Quail
Executive Director

cc: parties of record

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0040

November 13, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas (Vancouver Island) Inc. ("TGVI") 2010 and 2011 Revenue Requirements and Rate Design Application, Project No. 3698563

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). We confirm that the CEC accepts the terms of the final version of the Negotiated Settlement Agreement on the above-noted Application circulated by TGVI on November 5, 2009 and have no comments on that draft.

The CEC thanks the Commission staff and facilitator, TGVI and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: TGVI
cc: Registered Intervenors

BC hydro
FOR GENERATIONS

Leon Cender
Manager, Power Acquisitions
Phone: (604) 623-4436
Fax: (604) 623-4335
Email: leon.cender@bchydro.com

November 13, 2009

Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: Project No. 3698563
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Terasen Gas (Vancouver Island) Inc. 2010 and 2011 Revenue Requirements and Rate Design Application - Negotiated Settlement Agreement

BC Hydro acknowledges receipt of the final version of the Negotiated Settlement Agreement from Terasen Gas (Vancouver Island) Inc. (TGVI) and that the company has reviewed the document.

BC Hydro accepts the Negotiated Settlement Agreement and confirms that it has taken no position with respect to matters reflected in the Negotiated Settlement Agreement other than matters related to the Rate Design and those referred to in items 21 and 22 of the Negotiated Settlement Agreement.

Yours sincerely,

Leon Cender

Leon Cender
Manager, Power Acquisitions

cc. BCUC: Philip Nakoneshny
TGVI – Tom Loski
BCOAPO et al. – Jim Quail
CEC – Chris Weafer

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-141-09

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates

BEFORE: A.W.K. Anderson, Panel Chair/Commissioner
D.A. Cote, Commissioner
M.R. Harle, Commissioner

November 26, 2009

O R D E R

WHEREAS:

A. On June 15, 2009 Terasen Gas Inc. ("Terasen Gas") filed an application for approval of interim and permanent delivery rates effective January 1, 2010 and January 1, 2011 (the "Application") pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the "Act"), representing an increase of 5.3 percent for 2010 and 4.1 percent for 2011; and

B. Terasen Gas sought other approvals in the Application, including Orders pursuant to sections 59 to 61 of the Act, approving Tariff changes effective January 1, 2010 for Compression and Refueling and Transportation Services for Natural Gas Vehicles and economic models for evaluating biogas projects and alternative energy extensions for geo-exchange, solar thermal and district energy systems to complement its core natural gas business; and

C. The interim and permanent delivery rates sought in the Application are subject to adjustment for any changes in Terasen Gas' allowed return on equity and capital structure; and

D. Terasen Gas proposed a written hearing process to address the Application but was open to a Negotiated Settlement Process ("NSP") addressing all of the issues; and

E. In accordance with Commission Order G-76-09, a Workshop was held July 6, 2009 for a review of the Application and a first Procedural Conference was held on July 15, 2009. Commission Order G-89-09 established the requirement for a second Procedural Conference, held on September 25, 2009 to address the regulatory process and preliminary timetable; and

F. At the second Procedural Conference, the Commission Panel received submissions on the principal issues arising from or related to the Application, process options for the review of the Application, location of the proceedings and other matters that would assist the Commission's efficient review of the Application. The primary issues raised were whether a separate Certificate of Public Convenience and Necessity ("CPCN") review was required for the Alternative Energy Solutions proposed in the Application and whether the regulatory process should be in the form of an oral or written hearing or NSP; and

G. The Intervenors expressed a wish to avoid a separate CPCN process for the Alternative Energy Solutions and all Intervenors supported an NSP for the review of the Application. The Intervenors submitted that, in the event that the NSP is not successful in resolving all issues, an Oral Public Hearing could be ordered by the Commission. Terasen Gas requested that, if an Oral Public Hearing is established, it be limited in scope; and

H. Terasen Gas proposed that its application for interim rate approval be deferred until the end of November 2009; and

I. By Order G-119-09, the Commission Panel established a regulatory timetable for an NSP commencing October 21, 2009. The settlement discussions concluded on November 3, 2009; and

J. On November 13, 2009, the Negotiated Settlement Agreement ("NSA"), together with the Letters of Support received from the participants in the NSP, the Letter of Comment from Commission Staff and Terasen Gas' response to the Letter of Comment ("Settlement Package"), was made public and circulated to the Commission Panel; and

K. The Settlement Package was also distributed to Registered Intervenors who did not participate in the NSP ("Other Intervenors"). The Other Intervenors were requested to provide their comments on the Settlement Package to the Commission by November 20, 2009. The Commission Panel received no comments from Other Intervenors regarding the Settlement Package; and

L. The Commission Panel having reviewed the proposed NSA and the comments related thereto and noting the support of all parties to the proposed Negotiated Settlement Agreement, in which only sections 12(a) and (b) are severable, subject to the implementation of section 12.2, considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 and 89 of the Act the Commission orders as follows:

1. The Negotiated Settlement Agreement attached as Appendix A to this Order is approved.

2. TGI is to file an amended Summary of Rates and Bill Comparison schedules based on the Negotiated Settlement Agreement.

3. The Commission will accept, subject to timely filing by TGI, amended permanent Gas Tariff Rate Schedules in accordance with the terms of this Order. TGI is to provide notice of the permanent rates to customers via a bill message, to be reviewed in advance by Commission Staff to confirm compliance with this Order.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of November 2009.

BY ORDER

Original signed by:

A.W.K. Anderson
Panel Chair/Commissioner

Attachment

ERICA HAMILTON
COMMISSION SECRETARY
Commission. Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 29797

VIA EMAIL

November 13, 2009

Registered Intervenors
(*TGI-2010-11RR-RI*)

Dear Registered Intervenors:

Re: Terasen Gas Inc.
2010-2011 Revenue Requirements Application
Negotiated Settlement

Enclosed with this letter is the proposed settlement package for Terasen Gas Inc.'s 2010-2011 Revenue Requirements Application.

This settlement package is now public and is being submitted to the Commission and all Intervenors. Also enclosed are Letters of Comment received to date from the participants in the negotiated settlement process.

Prior to consideration by the Commission, Intervenors who did not participate in the settlement negotiations are requested to provide to the Commission with their comments on the settlement package by Friday, November 20, 2009. Thereafter, the Commission will consider the settlement package. A public hearing may not be required unless there is significant opposition to the proposed settlement.

Yours truly,

Y. Lapierre
for: Erica M. Hamilton

PWN/yl
Attachments
cc: Mr. Tom Loski
Chief Regulatory Officer
Terasen Gas Inc.
(Via Email: *regulatory.affairs@terasengas.com*)

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates
Negotiated Settlement Process

WHEREAS:

A. On June 15, 2009, Terasen Gas Inc. ("TGI") filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application"); and

B. Amongst other things, the Application sought:

1. An order pursuant to sections 59 to 61 of the *Utilities Commission Act* (the "Act"), approving delivery rates for all non-bypass customers effective January 1, 2010 and January 1, 2011, representing an increase of 5.3 percent for 2010 and an additional 4.1 percent for 2011, subject to changes in TGI's allowed return on equity ("ROE") and capital structure; and

2. An order pursuant to section 44.2 of the Act approving an expenditure schedule for the continuation in 2011 of TGI's residential and commercial Energy Efficiency and Conservation ("EEC") funding, as well as new EEC funding for 2010 and 2011 for interruptible industrial programs and innovative technologies; and

3. New tariff offerings and economic tests for Compression and Refuelling and Transportation Services for Natural Gas Vehicles ("NGV"), geo-exchange, solar thermal and district energy systems and a pilot program for Biogas; and

C. A complete listing of the relief sought by TGI in the Application was included in Section D (pages 513-516)[1] of the Application; and

D. In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a procedural conference was held on July 15, 2009, and TGI responded to two rounds of Information Requests; and

E. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second procedural conference was held on September 25, 2009; and

---

1 Page 516 of the Application was amended on September 18, 2009.

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

F. On October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application; and

G. The Parties to the NSP were TGI, British Columbia Old Age Pensioners et al. ("BCOAPO"), Commercial Energy Consumers Association of British Columbia ("CEC"), Teck Coal Ltd. ("Teck"), and the Ministry of Energy, Mines and Petroleum Resources ("MEMPR") (collectively referred to in this Agreement as the "Parties"); and

H. At the outset of the NSP on October 21, 2009, Commission Staff provided the Parties with a document prepared by the Commission Panel titled "Issues of Particular Concern to the Commission Panel", a copy of which is appended as Appendix 1 to this Agreement; and

I. The NSP was held on October 21-23, 30, and November 3 and 4, 2009; and

J. The Parties have negotiated in good faith to achieve a compromise settlement, reflected in this Agreement, of the issues raised by the Application, and the Commission Panel document referenced in recital H above, and further consider the Agreement reached to be fair, just and reasonable; and

K. This Agreement consists of four Parts:

Part I includes general provisions;

Part II includes the items agreed to that differ from what was requested in the Application;

Part III includes the items agreed to that remain as proposed by TGI in the Application; and

Part IV includes revised financial schedules reflecting all items set out in the Agreement.

NOW THEREFORE THE PARTIES AGREE AS FOLLOWS

PART I – GENERAL

1. <u>Agreement a Product of Compromise</u>

The Parties recognize and emphasize that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agree that any compromises resulting from this Agreement are without prejudice to the Parties' ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

2. Whole Agreement

Unless otherwise stated in this Agreement, portions of this Agreement cannot be removed or changed by the Commission without nullifying the whole Agreement.

3. TGI to Manage Business

The Parties agree that TGI will have the discretion to manage its business and determine how best to allocate the overall O&M and Capital expenditures stipulated in this Agreement.

4. Final IFRS Rate-regulated Activity Standard

The Parties acknowledge that this Agreement is predicated on the Final IFRS Rate-regulated Activity Standard permitting the financial accounting treatment contemplated in this Agreement in the manner outlined in the current Exposure Draft on Rate-regulated Activities. The Parties agree that if, in TGI's opinion, the Final IFRS Rate-regulated Activity Standard differs from the current Exposure Draft on Rate-regulated Activities so as not to permit the financial accounting treatment contemplated in this Negotiated Settlement Agreement, which among other things anticipates the recognition of regulatory assets and liabilities for external reporting purposes, then TGI is at liberty to apply to the Commission during the period of this Agreement for a determination of that issue, and to seek changes in the regulatory treatment contemplated in this Agreement to accord with the Final IFRS Rate-regulated Activity Standard, with the resulting impacts flowed through into rates commencing in 2011.

PART II – AGREED CHANGES FROM THE APPLICATION

5. Delivery Rates

The Delivery rate changes for 2010 and 2011 that would flow from this Agreement would be a decrease of 1.73 per cent in 2010 and an increase of 3.93 per cent in 2011, subject to being updated as contemplated in this Agreement. Issue No. 5 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "2010 Rate Changes – in the event that a 2010 rate reduction were to occur as a result of negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability."

Therefore, the Parties agree that this Agreement will not result in a decrease in delivery rates for 2010 and that the 2010 forecast revenue surplus will be recorded in a 2010 Revenue Surplus Deferral Account and be applied to offset any forecast increase in delivery rates in 2011. The forecast 2010 revenue surplus of $9.2 million per Schedule 1 included in Part IV of this Agreement, is recorded in the 2010 Revenue Surplus Deferral Account, which will be amortized in 2011 to reduce the 2011 forecast revenue deficit. The 2010 Revenue Surplus Deferral Account will be included in Rate Base.

However, the delivery rates for 2010 and 2011 will be updated to reflect changes in TGI's allowed ROE and capital structure flowing from the Commission's decision in TGI's concurrent ROE and Capital Structure Application[2], or as adjusted from time to time by the Commission. Nothing in this Agreement precludes TGI from applying to the Commission in 2010 or 2011 for changes to its allowed ROE and capital structure.

6. Service Quality Indicators

The Parties agree that TGI will report on the same SQI's as set out in the 2004-2007 PBR Agreement and the 2008-2009 extension thereof through quarterly postings on TGI's website.

7. Customer Additions Forecast

The Parties agree that TGI's net Residential customer additions forecast is revised to be 5,952 in 2010 (increase of 352 from Application[3]) and 6,166 in 2011 (increase of 316 customers from the number specified in the Application), reflecting the updated published CMHC Q3 2009 forecast, and TGI's year end 2009 number of customers has additionally been updated to be 835,862. Customer additions for the other rate classes remain unchanged from what was specified in the Application[4].

8. Use Per Customer Rates

The Parties agree that the Residential annual use per customer is revised upward from 89.7 GJ to 91.7 in 2010 and from 88.3 to 90.3 in 2011. Use per customer rates for the other rate classes remain unchanged from what was included in the Application (other than Industrial as set out in item 9).

9. Industrial Demand Forecast

The Parties agree that the industrial demand forecast is revised upwards from what was requested in the Application based on responses TGI has since received from the 2009 Industrial Survey and actual year-to-date demand. The revised industrial demand forecast includes forecast demand of 46.5 PJ and 46.5 PJ (compared to 43.4 PJ and 43.3 PJ as presented in the Application) for 2010 and 2011 respectively.

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[2] Filed jointly by the Terasen Utilities [TGI, Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.] on May 15, 2009.

[3] See Application, page 276

[4] IBID

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

10. Inclusion of SCP Capacity in MCRA

The Parties agree that TGI will continue for 2010 and 2011 to include in the MCRA the $3.6 million representing the annual cost of Southern Crossing Pipeline (SCP) capacity, because the benefits and use of the SCP capacity are used by Core Market Customers (Rate Schedules 1-7).

11. Energy Efficiency and Conservation ("EEC") Funding for 2010

The Parties agree as follows in respect of the EEC funding sought by TGI for 2010:

(a) TGI will reallocate from residential and commercial EEC programs an additional $1.6 million from the amount approved for 2010 in the EEC Decision[5] to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2010.

(b) EEC funding for industrial interruptible programs for 2010 will be $435,000, which is the amount requested by TGI in the Application.

(c) EEC funding for innovative technologies will be $2.3 million for 2010, which is the amount requested by TGI in the Application.

(d) All agreed to EEC expenditures will be considered and evaluated within the existing portfolio, and be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average Total Resource Cost ("TRC") of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

12. EEC Funding for 2011

12.1 The Parties agree as follows in respect of the EEC funding sought by TGI for 2011:

(a) EEC funding for residential and commercial programs for 2011 will be $23.075 million, which is the amount requested by TGI in the Application.

(b) TGI will reallocate from 2011 residential and commercial EEC funding ($23.075M for 2011) an additional $1.6 million (from the $0.8 million included in the Application) to low income and rental housing programs. This brings the total for low income and rental housing programs to $2.4 million for 2011.

---

[5] Decision and Order No. G-36-09 dated April 16, 2009 in the TGI-TGVI Energy Efficiency and Conservation Application

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NEGOTIATED SETTLEMENT AGREEMENT
TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

(c) EEC funding for industrial interruptible programs will be $1.875 million for 2011, which is the amount requested by TGI in the Application.

(d) EEC funding for innovative technologies will be $4.669 million for 2011, which is the amount requested by TGI in the Application.

(e) All agreed to EEC expenditures will be considered and evaluated within the existing EEC portfolio, and will be subject to the same financial treatment, as per the Commission's EEC Decision dated April 16, 2009 (Application, page 514, Item 6). However, Innovative Technology programs will be managed by TGI as a separate segment of the overall portfolio to have a weighted average TRC of 1.0 or more. TGI will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee.

(f) TGI will report to the Commission on industrial interruptible and innovative technology programs as part of TGI's annual report on EEC activities required under the EEC Decision.

The Parties offer the following rationale for the agreed upon 2011 EEC funding.

All Parties agree that it is important to maintain EEC funding levels in 2011 to allow customers to have continued access to EEC programs and incentives. The residential and commercial EEC programs relating to the $23.075 million funding in 2011 on a portfolio basis in aggregate have a TRC of one or more. This means that, from a resource perspective and on a portfolio basis, these programs are expected to yield favourable results for customers. The predictability and continuity of these programs on a sustained basis is critical to their overall success.

Issue No. 1 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "EEC Program – TGI is to provide results of programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding."

There are practical difficulties associated with the approach identified by the Commission Panel. They include the following:

- As per the EEC Decision (Order No. G-36-09), TGI will be reporting 2009 activities and results by no later than March 31, 2010. This report will also outline the forecasted activities and programs for 2010. Recognizing the timing of the recent EEC Decision and its current implementation in the Fall of 2009, the EEC Report for 2009 results will give the Commission and stakeholders another check point to validate the level of spend for 2011. However, there is expected to be very little additional information on the results of programs available in March 2010 than exists presently and is included in the evidentiary record of this proceeding. TGI's

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TERASEN GAS INC.
DATED THURSDAY, NOVEMBER 5

EEC programs only completed start up phase in the Fall of 2009. It typically takes longer than 6-8 months to achieve momentum with EEC programs. There will be no information available in March 2010 on results for industrial programs or programs relating to innovative technologies initiated in 2010 as a result of this Agreement. The information that the Commission Panel appears to desire will be more likely included in TGI's 2010 results report to be filed in March 2011.

- Employees responsible for the programs at TGI, whose salaries are funded from EEC funding, will face the prospect of losing their jobs in 2011. This could lead to employee retention issues. Employee turnover issues may disrupt the program implementation progress and potentially be more costly if EEC activity is ceased and later resumed.

- Programs will need to begin winding down in advance of 2011 if the 2011 funding is not approved. For example, programs will need to have an end date of December 31, 2010 which may not yield positive results since programs will be winding up in the middle of the heating season.

12.2 The Parties agree that the Commission may sever Section 12.1 (a) and (b) above from this Agreement, with the remainder of this Agreement remaining in force and effect. If the Commission severs Section 12.1 (a) and (b), then the Parties agree that the following provisions take effect:

(a) The Residential and Commercial EEC programs totaling $23.075 million in 2011 will be removed from the EEC expenditure forecast and the revenue requirements for 2011. (If 12.2 takes effect, the financial schedules in Part IV of this Agreement and the revenue requirements resulting from this Agreement will be revised to reflect this).

(b) The Parties agree that the first annual report on EEC Activities, which was due to be filed on March 31, 2010 pursuant to Order No. G-36-09, can be filed on or before June 30, 2010. Concurrent with that report, TGI will file an application with the anticipation of a decision within 120 days after filing. The application will include requests for:

i. approval of the above EEC funding for 2011;

ii. approval of the same financial treatment approved in the EEC Decision; and

iii. approval for the continuation of the portfolio approach and assessment methodology as approved in the EEC Decision.

13. Alternative Energy Solutions

Alternative Energy Solutions ("AES") means Geo-exchange, Solar-thermal and District Energy Systems as those terms are described in the Application.

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TERASEN GAS INC.
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Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates.

The Parties agree that the costs incurred by TGI to provide AES should not be recovered as part of natural gas service rates, and visa versa. The Parties agree that TGI's proposed New Energy Solutions Deferral Account, attracting AFUDC, is an appropriate mechanism to address allocation issues as between TGI's gas customers and TGI's AES customers. Therefore, the Parties agree that the new Energy Solutions Deferral Account will remain in effect pending a future rate design application at an unspecified future date after 2011 and will capture and record the following (plus AFUDC) to be recovered from AES customers:

(a) Direct costs associated with AES projects as outlined on pages 267-268 of the Application, including cost of design, equipment, etc. constructing and financing; and

(b) Sales and marketing O&M and other development costs will be directly charged to the deferral account by time sheets or other direct charge (estimated at $1.0 million in 2010 and $1.5 million in 2011, representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011); and

(c) An appropriate overhead allocation, which the parties have agreed will be $500,000 in each of 2010 and 2011 (representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011).

Revenues received from customers for all AES projects, which are based on contracts approved by Commission will be recorded in the AES deferral account.

The risk of non-recovery of amounts in the New Energy Solutions Deferral Account will not be borne by natural gas ratepayers. The Parties agree that any debit balance in the New Energy Solutions Deferral Account will not be recovered through natural gas rates and any credit balance will not be applied to reduce natural gas rates.

In evaluating AES projects, TGI will apply the economic test outlined in the Application. The Parties agree that the proposed GT&C (Section 12A – Alternative Energy Extensions) are acceptable. Pursuant to the *Utilities Commission Act,* within the Alternative Energy class of service, project-specific contracts with AES customers will be filed with the Commission for acceptance as a rate, at which time the Commission may review and adjust the economic test and GT&C Section 12A – Alternative Energy Extensions.

The CPCN threshold of $5 million applies to AES projects brought forward in 2010 and 2011.

The Parties agree that it is premature to address issues relating to the gas load and gas consumption profiles of AES projects that incorporate a natural gas component. Such issues are appropriately addressed in a future rate design application, once TGI has sufficient AES customers that take gas so as to provide reliable information on gas load and gas consumption profiles.

TGI will capture costs and revenue on a project specific basis and will report on AES projects as part of the next Revenue Requirements application.

14. Natural Gas for Vehicles ("NGV")

The Commission Issue No. 2 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Natural Gas Vehicles ("NGV") – if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?"

The Parties agree:

(a) NGV Rate Schedule 26 - NGV Transportation Service should be approved as filed.

(b) The marketing costs in support of NGV that are included in the revenue requirements Application are appropriately recoverable in 2010 and 2011 rates.

(c) Upon acceptance of this Agreement by the Commission, TGI withdraws its request in this Application for the following:

  i. Rate Schedule 6C NGV Compression and Refueling Service and 6A NGV Refueling Service; and

  ii. the Compression Service ("CS") Test; and

  iii. NGV non-rate base deferral account.

The Parties acknowledge that these requests are being withdrawn by TGI to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI's withdrawal of its requests regarding NGV is without prejudice to TGI's right to bring forward similar requests in 2010 or 2011 or otherwise in the future. The Parties acknowledge that TGI intends to develop this area of business and that TGI anticipates it will bring forward applications on NGV projects to the Commission on a case-by-case basis during the term of this Agreement and in future years. The Parties agree that TGI is at liberty to do so.

15. Biogas

Issue No. 3 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Biogas – to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost."

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The Parties agree that, upon acceptance of this Agreement by the Commission, TGI withdraws its requests in this Application related to Biogas. The Parties acknowledge that these requests are being withdrawn to facilitate a settlement on other issues presented in this Application. The Parties agree that TGI will bring forward an application (the "Biogas Application") during the test period that will:

(a) Address the economic assessment model; and

(b) Provide Biogas rates (including green rate, transportation rate, etc.); and

(c) Provide for recovery of costs associated with providing Biogas service.

TGI may include in the Biogas Application any Biogas Projects under development at that time. TGI is, however, not precluded from applying for Commission approval in respect of individual Biogas Projects at any time, either prior to the Biogas Application or afterwards.

16. CPCN Threshold

Issue No. 6 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "CPCN threshold – stay at $5 million."

The Parties accordingly agree that the CPCN threshold will remain at $5 million for 2010 and 2011. TGI's Category B Capital Expenditures forecast for the forecast period will be revised to reflect this change (please see item 18 below).

17. Category A Capital

The Parties agree that Category A Capital will be $43.3 million for 2010 and $46.0 million for 2011, reflecting the proposed amount updated to reflect the published CMHC Q3 2009 forecast, and TGI's adjusted re-forecasted year end net customer addition numbers (as set out in item 7).

18. Category B and Category C Capital

As a consequence of the CPCN threshold being established at $5 million for 2010 and 2011 (see item 16 above), TGI will file CPCN applications for the Huntingdon and Kootenay Crossing projects identified in TGI's Application. The Category B Capital will consequently be reduced by $2.2 million in 2010 and $16.0 million in 2011. TGI will seek deferral treatment for 2011 of the capital costs associated with those projects at the time of filing the CPCN Applications.

The Parties agree that Category B and C Capital will be reduced by a total of $3 million in each of 2010 and 2011. For the purposes of the determination of revenue requirements

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with this Application, Category B Capital has been reduced by $1 million and Category C IT Capital has been reduced by $2 million.

The revised Category B Capital Expenditures, reflecting both the CPCN adjustment and the $1 million reduction in spending, are now $17.4 million in 2010 and $14.9 million in 2011.

The revised Category C Capital Expenditures, reflecting the $2 million IT Capital reduction, are now $32.8 million in 2010 and $32.7 million in 2011.

19. Gross O&M (to be recovered from gas customers)

The Parties agree that the proposed gross O&M, before shared service allocations, recoverable from gas customers for 2010 and 2011 is reduced from the amounts included in the original Application by $4.0 million in 2010 and a further $1.5 million (for a total impact of $5.5 million) in 2011. This reduction of Gross O&M will result in a reduction in the pool of costs subject to the Shared Services Agreement with TGVI and with TGW by an estimated $3.3 million in 2010 and $4.8 million in 2011. Therefore, and as discussed in Item 21, the final Gross O&M to be included in TGI's cost of service for 2010 and 2011 will be determined based on the Shared Services and Corporate Services allocations determined in the TGVI RRA.

20. Interest Expense

The Parties agree that TGI will update its assumptions around both the issuance of long-term debt and the associated interest rates. TGI has determined that Long-term Debt Series 25 will not be issued December 1, 2009 as originally forecast and is now anticipated to be issued April 1, 2010. In addition, the interest rate forecast for Long-term Debt Series 26, to be issued July 1, 2011, has been revised downwards from 6.13 per cent to 5.65 per cent.

21. Shared Services/Corporate Services Allocations

The 2010 and 2011 revenue requirements stipulated in this Agreement are based on TGI's proposed Shared Services and Corporate Services allocation for 2010 and 2011. The Parties acknowledge, however, that the final amount allocated to TGI for Shared Service and Corporate Services cannot be confirmed until the Commission determines the TGVI RRA. The Parties agree that if the amounts allocated to TGVI for Shared Services and/or Corporate Services for 2010 or 2011 changes from that agreed to in this Agreement as a result of a settlement or decision in the concurrent TGVI RRA proceeding, then the amount(s) allocated to TGI and its revenue requirements for 2010 and 2011 will be updated by a corresponding amount to ensure recovery of all of the combined Corporate Services and Shared Services costs.

22. Depreciation Study

The Parties agree that the depreciation rates specified in the Gannett Fleming study included the Application under Appendix H-2 for Parts I-III, and in the Supplemental filing dated July 8, 2009 for Parts IV and V, will be implemented effective January 1, 2010, with the exception of:

(a) Masonry Structures, which has been updated to 40 years instead of 22.88 years; and

(b) the component of those rates that represent recovery of negative salvage (see item 23 below).

Adjusting for the Masonry Structures, negative salvage, and the impacts of capitalized overhead and capital additions changes yields total depreciation expense of $98.3 million in 2010 and $100.5 million in 2011, of which approximately $6.3 million results from the updated Gannett Fleming depreciation study.

The Parties agree that TGI will undertake an updated depreciation study to be included as part of TGI's next Revenue Requirements Application. This study will address the methodology and rates for net negative salvage to be included in cost of service for future periods. TGI will work with Commission staff and a depreciation rate specialist in determining the requirements of the study.

23. Negative Salvage Values

On an annual basis, TGI includes a provision for estimated net negative salvage value (removal costs less proceeds) in its depreciation rates. This treatment recognizes that net negative salvage value is a cost of providing service using the asset and should be recovered from customers over the useful life of the asset. An alternative treatment is to recover the net negative salvage values at the time they are incurred resulting in future customers paying for the removal costs, which TGI views as inappropriate. The inclusion of a provision for estimated net negative salvage value in depreciation rates is a practice that has been followed by TGI historically, and with this RRA TGI had proposed continuation of this treatment. This treatment is consistent with the BCUC Uniform System of Accounts and is generally followed by other investor-owned utilities in British Columbia and across Canada.

The Parties agree that for the purposes of the two year period covered by this Agreement, the provision for net negative salvage (net removal costs) will be removed from the depreciation estimates. Instead, an estimate of the amount of net removal costs to be incurred in each of the years 2010 and 2011 ($8.038 million and $11.29 million) will be included in the cost of service and recovered from customers in each of those years. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service will be recorded in a new deferral account created for this purpose that will be called the "Removal Cost Deferral Account". The amount accumulated in the Removal Cost Deferral Account over the two year period of this Agreement will be recovered from (or returned to) customers in 2012.

TGI continues to be of the position that removal costs should be recovered over the service life of the asset and not at the time the removal costs are actually incurred. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the removal costs and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

24. Unrecovered Losses

Issue No. 7 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "Unrealized losses in rate base – should some of these losses be to the shareholder? Parties should present a separate settlement package."

Unrealized (unrecovered) losses relate to Unrecovered Depreciation on assets used 100 per cent for the provision of utility service to ratepayers (as discussed in the response to BCUC IR 2.131.1.4).

The Parties agree that the treatment for unrecovered losses as proposed in the Application is acceptable for the 2010 and 2011 period covered by this agreement. TGI will work with Commission staff and a depreciation rate specialist in determining both the methodology and estimates for the unrecovered losses and include the documentation to support the rates in its next depreciation study filed as part of its next Revenue Requirement Application.

25. Changes to CCA Rates

TGI amended its 2007 and 2008 tax returns to reflect changes to CCA rates announced in 2007 but not enacted until 2009. TGI proposed this benefit be shared in accordance with the terms of the PBR settlement. Some Parties have expressed the view, however, that all of the benefit should have been flowed through to customers via the Tax Deferral Account. The Parties, acting in good faith, have concluded that they have a fundamental and legitimate disagreement regarding the terms of the 2004-2009 PBR Settlement Agreement as it relates to the items to be included in the Tax Deferral Account. TGI has nevertheless agreed, as a compromise in furtherance of reaching an overall Agreement among the Parties, to include the full value of the incremental tax benefit associated with the difference in the CCA rates for 2007 and 2008 totalling $921,000 and remove the proposed 50% sharing benefit from the Earnings Sharing Mechanism.

26. Taxes – Tax Benefits Relating to Prior Periods – SCP Landscaping Costs

TGI had proposed to accelerate the deduction of the remaining Regulatory Tax balance of SCP Landscaping costs (amounting to approximately $8.2 million) in 2009. That proposal would have resulted in the related tax benefit of approximately $2.4 million being flowed through the Earnings Sharing Mechanism pursuant to the PBR Settlement Agreement, resulting in a net benefit to customers of approximately $1.2 million.

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The Parties agree that, instead, TGI will continue to amortize the balance of SCP Landscaping costs for 2009 as contemplated in the approved rates for 2009 and consistent with prior years, resulting in a deduction of approximately $0.3 million for Regulatory Tax purpose in 2009 and a related tax benefit. TGI will then deduct the remaining balance (approximately $7.9 million) in 2010 with the full value of the remaining benefit (approximately $2.3 million) going to customers reflected as a reduction in revenue requirements in 2010.

The Parties agree that the acceleration of this benefit to customers was the result of tax planning actions taken by TGI and acknowledge that the agreed upon treatment set out above reflects customers receiving 100% of the value of the deductions of the SCP Landscaping costs. The intervenor Parties to this Agreement will not seek any additional recovery in respect of SCP Landscaping costs.

27. Overheads Capitalized

The Parties agree to a change in the overheads capitalized rate to 14 per cent of Gross O&M for 2010 and 2011 which reflects the approximate actual Overheads Capitalized rate for 2009.

28. International Financial Reporting Standards ("IFRS") 2010 Impact

Issue No. 4 in the Commission Panel's "Issues of Particular Concern to the Commission Panel" stated:

> "International Financial Reporting Standards ("IFRS") – no IFRS impact in 2010."

The Parties agree to defer the 2010 revenue requirement impact of IFRS to be recovered in rates in 2011 (relating specifically to capitalization of the current service portion of pension and OPEB related costs; capitalization of inspection costs; and timing of depreciation expense) up to a maximum of $1.0 million. Amounts, if any, over $1.0 million would be deferred and recovered in rates after 2011 based on the amortization approved by the Commission at that time.

PART III – REQUESTS UNCHANGED FROM THE APPLICATION

The Parties agree to the following items set out in this section, which are consistent with the proposals in TGI's Application.

29. Rate Proposals as per Application Part III, Section D .1 - Approvals Sought

The Parties agree to the following rate proposals, as set out in TGI's Application:

(a) Allocation of delivery margin rate changes - Annual margin increase allocated to variable (volumetric & demand) based delivery charges, with no change to fixed (basic and admin fee) charges in each year (Application Page 513, Item 1).

(b) Earnings Sharing Mechanism (ESM) rider (incl. end of term capital) - Change the ESM rate rider to be ($0.040)/GJ effective January 1st, 2010, and change the estimated ESM rate rider to be ($0.046)/GJ effective January 1st. 2011. ESM amount to include End of Term Capital phase out and to be amortized over two years. The final 2011 rider amount will be adjusted based on 2009 actual earnings. TGI will submit an application to change the 2011 ESM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application Page 513, Item 3).

(c) Rate Stabilization Adjustment Mechanism (RSAM) rider - Change the RSAM rate rider to be ($0.053)/GJ effective January 1st, 2010 and change the estimated RSAM rate rider to be ($0.052)/GJ effective January 1st, 2011. The 2011 rider amount will be adjusted based on 2009 actual results and 2010 year to date actual results. TGI will submit an application to change the 2011 RSAM rate rider at the same time it submits its Q4 quarterly gas cost report in early December 2010 (Application - Page 514 Item 4).

30. <u>Accounting Policy Changes as per Application Part III, Section D.1 - Approvals Sought - to be effective January 1, 2010</u>

The Parties agree to the following accounting policy changes, as set out in TGI's Application:

(a) Training and Feasibility Study Costs to be treated as O&M expense, rather than capital (Application Page 515 and 516, Item 11).

(b) Capitalization of Major Inspection Costs, including the creation of a new Asset Class (Application Page 515 and 516, Item 11).

(c) Capitalization of the Current Service portion of Pensions and OPEBs expense that is applicable to capital projects (Application Page 515 and 516, Item 11).

(d) Capitalization of Deprecation on Assets used in Construction (Application Page 515 and 516, Item 11).

(e) All capital expenditures, including CPCNs, to be included in plant in service (and rate base) in the month following the available-for-use date, with depreciation starting at that time (Application Page 515 and 516, Item 11).

(f) Treatment of Vehicle Lease as a capital lease and inclusion of the NBV of vehicles in rate base (Application Page 515 and 516, Item 11).

(g) Discontinuation the Software Tax Credit as part of the CIAC additions (Application Page 515 and 516, Item 11).

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31. Various Accounting Related Proposals as per Application Part III, Section D .1 - Approvals Sought effective January 1, 2010

The Parties agree to the following accounting related changes, as set out in TGI's Application:

(a) Adoption of the Cash Working Capital Lead/Lag Days as set out in the Lead/Lag study (Application page 515, Item 8c).

(b) Consolidated Core Market Administration Expenses (for TGI, TGVI and TGW), including allocation percentages to TGVI and TGW (Application page 515, Item 8d).

(c) Modify the Pricing Methodology for Company Use Gas to be based on market-based Sumas pricing, rather than pricing for expired "netback" contracts (Application page 514, Item 7a).

(d) The MCRA will absorb any volumes not used or excess volumes required for company use gas, as opposed to the O&M costs being adjusted for the differences (Application page 514, Item 7b).

32. Tariff Change Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 12 & 13

The Parties agree to the following Tariff changes, as set out in TGI's Application:

(a) New NGV Transportation Service (RS 26)

(b) Revised Fee New Customer Application fee from $85 to $25

(c) Revised Fee Meter Testing fee from $30 to $60

33. Deferral Account Proposals as per Application Part III, Section D .1 - Approvals Sought, Item 10

The Parties agree to the continuation, modification or adoption of the following deferral accounts as set out in TGI's Application:

(a) Deferral Accounts - No Change:

i. CCRA, MCRA, RSAM, and associated Interest and Revelstoke Propane (Application pages 429 and 430, Items (1) (a), (1) (b), (1) (c), (1) (d), (1) (e)).

ii. NGV Conversion Grants (Application page 432, Item (2) (b)).

iii. Property Tax variance (Application page 433, Item (3) (a)).

iv. Insurance variance (Application page 433, Item (3) (b)).

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v. BCUC Levies variance (Application page 433, Item (3) (d)).

vi. Interest variance (Application page 434, Item (3) (e)).

vii. Olympic Security costs (Application page 434, Item (3) (g)).

viii. IFRS conversion costs (Application page 435, Item (3) (h)).

ix. Accounts Amortized in 2010 (Application page 438, Item (6) (a)).

x. SCP PST Reassessment (Application page 439, Item (6) (b)).

xi. Deferred Service Line Installation Fee (Application page 439, Item (6) (d)).

xii. ESM (Application page 440, Item (6) (e)).

(b) Deferral Accounts - Modified:

i. SCP Mitigation Revenues Variance Account - combine the two currently approved accounts into one account (Application page 431, Item (1) (f)).

ii. Pension & OPEB variance - modify to add OPEB (Application page 433, Item (3) (c)).

iii. Tax variance - broader (changes in tax laws, practices, reassessments) (Application page 434, Item (3) (f)).

iv. Pension and OPEB funding Differences - expand to include pension funding differences and include addition in rate base not net of tax (Application page 437, Item (5) (c)).

(c) Deferral Accounts - New:

i. Interest variance calculation on gas in storage inventory (Application page 434, Item (3) (e)).

ii. Costs of applications (CCE, ROE, RRA) (Application page 435, Item (4)).

iii. IFRS Transitional Deferral Account (Application page 435, Item (5) (a)).

iv. Gains and Losses on Asset Disposition (Application page 436, Item (5) (b)).

v. CCE CPCN Costs (incremental non-capital costs plus timing impacts) (Application page 437, Item (5) (d)).

vi. LILO Reassessment (Application page 439, Item (6) (c)).

34. Transfer Pricing Policy (TPP) and Code of Conduct (COC)

The Parties agree that the existing COC and TPP Policies will be maintained.

PART IV – REVISED FINANCIAL SCHEDULES

The revised Financial Schedules follow.

13. Financial Schedules

Summary of TGI 2010 and 2011 Revenue Requirement Increase
Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 1

		2010 ($ Millions)		Incremental 2011 ($ Millions)	Cumulative 2011 ($ Millions)	
Rebase from Formula Capital and O&M						
Rate Base- Net Plant in Service						
Equity Finance Expense	$ (2.0)		$ -			
Debt Finance Expense	(3.0)		-			
Utility O&M	(8.0)		-			
Overheads Capitalized	1.3					
After Tax Depreciation	(10.0)		-			
Tax Impacts of Rebase Depreciation	(4.3)		-			
Other Revenue	2.6		-			
Taxes	1.0	$ (22.4)	-	$ -	$ (22.4)	
Volumes/Revenue Related						
Change in Gross Margin due to Customer Growth	$ (4.6)		(3.7)			
Change in Use Rate	(4.7)		4.7			
Change in Other Revenue	(1.6)		(1.9)			
All Others	(1.8)	(12.7)	(1.5)	(2.4)	(15.1)	
O&M Forecast						
Change in overheads capitalized- change in O&M	(1.2)		(0.7)			
Change in O&M & Vehicle Lease Forecast	14.9	13.7	11.5	10.8	24.5	
Depreciation & Amortization Forecast						
After Tax Change in Depreciation from GPIS Additions/Retirements	3.7		2.3			
Change in Amortization	(2.2)	1.5	4.0	6.3	7.8	
Other						
Higher Property Taxes	1.6		1.0			
Change in Income Tax Expense	(0.4)		(0.1)			
Rate Base changes to support customer growth	1.8		2.5			
Interest Expense	2.1		5.4			
Rounding Difference	0.2	5.3	(0.1)	8.7	14.0	
Total Revenue Increase/(Decrease) Before Accounting Standard Changes		$ (14.6)		$ 23.4	$ 8.7	
Accounting Standard Changes						
Change in Overhead Capitalized Rate & Methodology	11.2		-			
Impacts on O&M	(0.3)	10.9	(2.0)	(2.0)	8.9	
After Tax change in Depreciation Rates	20.8		0.4			
After Tax change in Depreciation Commencement	1.9		-			
Tax Impacts of Depreciation Changes	9.0	31.7	0.1	0.5	32.2	
Total Revenue Increase from Accounting Standard Changes		$ 42.6		$ (1.5)	$ 41.1	
Net Revenue Increase - June 15, 2009 Application		**$ 27.9**		**$ 21.9**	**$ 49.8**	
Negotiatied Settlement Process Adjustments- please refer to Settlement Agreement for detail		(37.1)			(28.8)	
Adjusted Revenue (Decrease) / Increase		$ (9.2)	-1.73%		$ 21.0	3.93%
2010 Revenue Surplus deferred (pre-tax)*		9.2			(9.2)	
Net Revised Revenue (Decrease) / Increase- Negotiated Settlement Agreement Nov 5, 2009		**$ -**			**$ 11.8**	

*After Tax 2010 Revenue Surplus is $6.5 million

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Core	2010 Non-Core	2010 Bypass and Special Rates	2010 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,487,998	$1,430,710	$61,497	$12,094	$1,504,300	$16,302	- Tab C-13, Schedule 16
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	16,276	-	-	16,276	16,276	-	- Tab C-13, Schedule 26
8								
9	Total Revenue	1,504,274	1,430,710	61,497	28,369	1,520,576	16,302	
10								
11	Less - Cost of Gas	(975,597)	(986,394)	(759)	(817)	(987,970)	(12,373)	- Tab C-13, Schedule 19
12								
13	Gross Margin	$528,677	$444,316	$60,738	$27,552	$532,606	$3,929	
14								
15	Revenue Deficiency (Surplus)	$27,865	$0	$0	$0	**$0**	($27,865)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.27%	0.00%	0.00%	0.00%	0.00%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.85%	0.00%	0.00%	0.00%	0.00%		
20								

TERASEN GAS INC.

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Section C
Tab 13
Schedule 3

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Core	2011 Non-Core	2011 Bypass and Special Rates	2011 Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,489,519	$1,433,011	$61,612	$12,094	$1,506,716	$17,197	- Tab C-13, Schedule 17
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Terasen Gas (Vancouver Island)	18,253	-	-	18,253	18,253	-	- Tab C-13, Schedule 27
8								
9	Total Revenue	1,507,772	1,433,011	61,612	30,347	1,524,969	17,197	
10								
11	Less - Cost of Gas	(976,614)	(988,047)	(759)	(821)	(989,627)	(13,013)	- Tab C-13, Schedule 21
12								
13	Gross Margin	$531,158	$444,964	$60,853	$29,526	$535,342	$4,184	
14								
15	Revenue Deficiency (Surplus)	$49,846	$10,340	$1,414	$0	**$11,754**	($38,092)	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	9.38%	2.32%	2.32%	0.00%	2.20%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.31%	0.72%	2.30%	0.00%	0.77%		
20								

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Tab 13
Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14	RSAM Revenue						
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 5

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14							
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Operating Leases	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	62,527	-	$62,527	(16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	$110,955	$87,450	$0	$87,450	($23,505)	
16							
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	
18							

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	59,491	8,639	$68,130	(39,328)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.50%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	$119,448	$80,940	$11,754	$92,694	($26,754)	
16							
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($7,090)	(X-Ref - Tab C-13, Schedule 5)
18							

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 8

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-	-	-	-	-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16							
17	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
20	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
24	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
25	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 9

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	Adjustments	Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16							
17	Adjustment to 13-Month Average	-	-	-	-	-	
18	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
19	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
20	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
21	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
22	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)		- Tab C-13, Schedule 61
24	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
25	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	
3	Unfunded Debt			88,809	3.50%	2.250%	0.08%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			887,309	35.01%	8.483%	2.97%	
6								
7		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	
8								
9	2010 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.49%	6.870%	4.22%	$107,064
11	Unfunded Debt		$88,809					
12	Adjustment, Revised Rates		-	88,809	3.50%	2.250%	0.08%	1,998
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			887,309	35.01%	8.470%	2.97%	75,155
15		(X-Ref - Tab C-13, Schedule 4)						
16		- Tab C-13, Schedule 8		$2,534,444	100.00%		7.27%	$184,217

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Reference	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.06%	6.836%	4.24%	
3	Unfunded Debt			76,982	2.93%	4.500%	0.13%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			920,331	35.01%	7.529%	2.64%	
6								
7		- Tab C-13, Schedule 9		$2,628,766	100.00%		7.01%	
8								
9	2011 REVISED RATES							
10	Long-Term Debt	- Tab C-13, Schedule 64		$1,631,453	62.06%	6.836%	4.24%	$111,518
11	Unfunded Debt		$76,982					
12	Adjustment, Revised Rates		4	76,986	2.93%	4.500%	0.13%	3,464
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			920,333	35.01%	8.470%	2.97%	77,952
15		(X-Ref - Tab C-13, Schedule 5)						
16		- Tab C-13, Schedule 9		$2,628,772	100.00%		7.34%	$192,934

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 12

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,423	113,863	-	113,863	1,440	- Tab C-13, Schedule 14
3	Transportation	88,255	90,743	-	90,743	2,488	- Tab C-13, Schedule 14
4		200,678	204,606	-	204,606	3,928	
5							
6	Average Rate per GJ						
7	Sales	$12.801	$12.565	$0.000	$12.565	($0.236)	
8	Transportation	$0.869	$0.811	$0.000	$0.811	($0.058)	
9	Average	$7.554	$7.352	$0.000	$7.352	($0.202)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,414,636	$1,430,710	$0	$1,430,710	$16,074	- Tab C-13, Schedule 16
13	- Increase / (Decrease)	24,497	-	-	-	(24,497)	- Tab C-13, Schedule 22
14		-					
15	Transportation - Existing Rates	73,362	73,591	-	73,591	229	- Tab C-13, Schedule 16
16	- Increase / (Decrease)	3,368		-	-	(3,368)	- Tab C-13, Schedule 22
17	**Total**	1,515,863	1,504,301	-	1,504,301	(11,562)	
18							
19	Cost of Gas Sold (Including Gas Lost)	975,597	987,970	-	987,970	12,373	- Tab C-13, Schedule 19
20							
21	**Gross Margin**	540,266	516,331	-	516,331	(23,935)	
22							
23	Operation and Maintenance	192,823	177,559	-	177,559	(15,264)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	49,193	49,193	-	49,193	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	103,796	88,893	-	88,893	(14,903)	- Tab C-13, Schedule 33
27	Removal Cost Provision		8,038	-	8,038	8,038	- Tab C-13, Schedule 33
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 33
29	NSP Provision (IFRS -$800 + ESM $225 + RSDA $6537)		5,963	-	5,963	5,963	
30	Other Operating Revenue	(22,422)	(22,455)	-	(22,455)	(33)	- Tab C-13, Schedule 26
31		323,390	307,191	-	307,191	(16,199)	
32	Utility Income Before Income Taxes	216,876	209,140	-	209,140	(7,736)	
33							
34	Income Taxes	31,622	24,923	-	24,923	(6,699)	- Tab C-13, Schedule 35
35							
36	**EARNED RETURN**	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 10
37							
38							
39	**UTILITY RATE BASE**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	- Tab C-13, Schedule 8
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.31%	7.27%		7.27%	-0.04%	- Tab C-13, Schedule 10

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 13

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	112,326	113,846	-	113,846	1,520	- Tab C-13, Schedule 15
3	Transportation	88,438	91,014	-	91,014	2,576	- Tab C-13, Schedule 15
4		200,764	204,860	-	204,860	4,096	
5							
6	Average Rate per GJ						
7	Sales	$12.997	$12.587	$0.000	$12.678	($0.319)	
8	Transportation	$0.898	$0.810	$0.000	$0.825	($0.073)	
9	Average	$7.668	$7.355	$0.000	$7.412	($0.256)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,416,102	$1,433,011	$0	$1,433,011	$16,909	- Tab C-13, Schedule 17
13	- Increase / (Decrease)	43,822	-	10,341	10,341	(33,481)	- Tab C-13, Schedule 24
14		-					
15	Transportation - Existing Rates	73,417	73,705	-	73,705	288	- Tab C-13, Schedule 17
16	- Increase / (Decrease)	6,024		1,413	1,413	(4,611)	- Tab C-13, Schedule 24
17	**Total**	1,539,365	1,506,716	11,754	1,518,470	(20,895)	
18							
19	Cost of Gas Sold (Including Gas Lost)	976,614	989,627	-	989,627	13,013	- Tab C-13, Schedule 21
20							
21	**Gross Margin**	562,751	517,089	11,754	528,843	(33,908)	
22							
23	Operation and Maintenance	201,617	184,625	-	184,625	(16,992)	- Tab C-13, Schedule 28
24	Vehicle Lease	-	-	-	-	-	
25	Property and Sundry Taxes	50,211	50,211	-	50,211	-	- Tab C-13, Schedule 32
26	Depreciation and Amortization	110,496	88,588	-	88,588	(21,908)	- Tab C-13, Schedule 34
27	Removal Cost Provision		11,290	-	11,290	11,290	- Tab C-13, Schedule 34
28	Capitalized Depreciation		-	-	-	-	- Tab C-13, Schedule 34
29	NSP Provision (IFRS $800 + ESM $225)		1,025	-	1,025	1,025	
30	Other Operating Revenue	(24,359)	(24,394)	-	(24,394)	(35)	- Tab C-13, Schedule 27
31		337,965	311,345	-	311,345	(26,620)	
32	Utility Income Before Income Taxes	224,786	205,744	11,754	217,498	(7,288)	
33							
34	Income Taxes	31,654	21,449	3,115	24,564	(7,090)	- Tab C-13, Schedule 36
35							
36	**EARNED RETURN**	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 11
37							
38							
39	**UTILITY RATE BASE**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	- Tab C-13, Schedule 9
40							
41	**RATE OF RETURN ON UTILITY RATE BASE**	7.37%	7.01%		7.34%	-0.03%	- Tab C-13, Schedule 11

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 14

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2010

			2010 Terajoules				
Line No.	Particulars	June 15, 2009 Application	Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,829.2	69,174.3	0.0	69,174.3	1,345.1	
3	Schedule 2 - Small Commercial	24,374.3	24,374.3		24,374.3	0.0	
4	Schedule 3 - Large Commercial	16,818.6	16,818.6		16,818.6	0.0	
5							
6	Schedules 1, 2 and 3	109,022.1	110,367.2	0.0	110,367.2	1,345.1	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,098.5	3,184.6		3,184.6	86.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,423.2	113,862.9	0.0	113,862.9	1,439.7	(X-Ref - Tab C-13, Schedule 4)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,849.7	11,080.5	0.0	11,080.5	(769.2)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,368.3		36,368.3	36,368.3	0.0	
24	Schedule 23 - Large Commercial	6,134.0	6,134.0		6,134.0	0.0	
25	Schedule 25 - Firm Service	13,159.6	12,944.4	873.1	13,817.5	657.9	
26	Schedule 27 - Interruptible Service	5,183.5	5,587.4		5,587.4	403.9	
22							
23	Total Transportation Service	88,255.2	43,849.5	46,893.9	90,743.4	2,488.2	(X-Ref - Tab C-13, Schedule 4)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,678.4	157,712.4	46,893.9	204,606.3	3,927.9	(X-Ref - Tab C-13, Schedule 23)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2011

			2011 Terajoules				
Line No.	Particulars	June 15, 2009 Application	Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	67,190.5	68,578.9	0.0	68,578.9	1,388.4	
3	Schedule 2 - Small Commercial	24,603.1	24,603.1		24,603.1	0.0	
4	Schedule 3 - Large Commercial	17,168.5	17,168.5		17,168.5	0.0	
5							
6	Schedules 1, 2 and 3	108,962.1	110,350.5	0.0	110,350.5	1,388.4	
7							
8	Schedule 4 - Seasonal	184.6	184.6		184.6	0.0	
9	Schedule 5 - General Firm	3,061.2	3,184.3		3,184.3	123.1	
10							
11	Industrials	0.0					
12	Schedule 7 - Interruptible	14.2	22.7		22.7	8.5	
13							
14	Schedule 6 - N G V Fuel - Stations	103.8	103.8		103.8	0.0	
15							
16	Total Sales	112,325.9	113,845.9	0.0	113,845.9	1,520.0	(X-Ref - Tab C-13, Schedule 5)
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	13,090.4	8,103.2	7,795.6	15,898.8	2,808.4	
20	- Interruptible Service	11,830.5	11,080.5	0.0	11,080.5	(750.0)	
21	Byron Creek (aka Fording Coal Mountain)	125.8		137.5	137.5	11.7	
22	Burrard Thermal - Firm	2,343.9		1,719.4	1,719.4	(624.5)	
23	TGVI - Firm	36,596.4		36,596.4	36,596.4	0.0	
24	Schedule 23 - Large Commercial	6,177.2	6,177.2		6,177.2	0.0	
25	Schedule 25 - Firm Service	13,102.0	12,944.1	873.1	13,817.2	715.2	
26	Schedule 27 - Interruptible Service	5,171.9	5,587.4		5,587.4	415.5	
22							
23	Total Transportation Service	88,438.1	43,892.4	47,122.0	91,014.4	2,576.3	(X-Ref - Tab C-13, Schedule 5)
24							
25	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,764.0	157,738.3	47,122.0	204,860.3	4,096.3	(X-Ref - Tab C-13, Schedule 25)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 16

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$897,420	$912,822	$0	$912,822	$15,402	
3	Schedule 2 - Small Commercial	297,556	297,556		297,556	-	
4	Schedule 3 - Large Commercial	189,604	189,604		189,604	-	
5	Schedules 1, 2 and 3	1,384,580	1,399,982	-	1,399,982	15,402	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,404	28,012		28,012	609	
9		28,881	29,490	-	29,490	609	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,414,636	1,430,710	-	1,430,710	16,074	(X-Ref - Tab C-13, Schedule 4)
16							(X-Ref - Tab C-13, Schedule 12)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,743	9,270	-	9,270	(473)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,411	16,411	-	16,411	-	
24	Schedule 25 - Firm Service	24,509	23,970	775	24,744	235	
25	Schedule 27 - Interruptible Service	6,270	6,658	-	6,658	388	
26	Total T-Service	73,362	61,497	12,094	73,591	229	(X-Ref - Tab C-13, Schedule 4)
27							(X-Ref - Tab C-13, Schedule 12)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,487,998	$1,492,207	$12,094	$1,504,300	$16,302	(X-Ref - Tab C-13, Schedule 23)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Gas Sales Revenue At Existing 2009 Rates: Core and Non-Core	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Core Sales**						
2	Schedule 1 - Residential	$891,764	$907,735	$0	$907,735	$15,971	
3	Schedule 2 - Small Commercial	300,831	300,831		300,831	-	
4	Schedule 3 - Large Commercial	193,720	193,720		193,720	-	
5	Schedules 1, 2 and 3	1,386,315	1,402,286	-	1,402,286	15,971	
6							
7	Schedule 4 - Seasonal	1,477	1,477	-	1,477	-	
8	Schedule 5 - General Firm	27,135	28,009		28,009	874	
9		28,613	29,487	-	29,487	874	
10	Industrials						
11	Interruptible - Schedule 7	130	194	-	194	64	
12							
13	N G V Fuel - Stations - Schedule 6	1,044	1,044		1,044	-	
14							
15	Total Core Sales	1,416,102	1,433,011	-	1,433,011	16,908	- Tab C-13, Schedule 5
16							(X-Ref - Tab C-13, Schedule 13)
17	**Transportation Service**						
18	Schedule 22 - Firm Service	6,380	5,189	1,270	6,459	79	
19	- Interruptible Service	9,729	9,270	-	9,270	(459)	
20	Byron Creek (aka Fording Coal Mountain)	53		53	53	-	
21	Burrard Thermal - Firm	9,996		9,996	9,996	-	
22	TGVI - Firm	-		-	-	-	
23	Schedule 23 - Large Commercial	16,525	16,525	-	16,525	-	
24	Schedule 25 - Firm Service	24,475	23,969	775	24,744	269	
25	Schedule 27 - Interruptible Service	6,258	6,658	-	6,658	400	
26	Total T-Service	73,417	61,612	12,094	73,705	288	- Tab C-13, Schedule 5
27							(X-Ref - Tab C-13, Schedule 13)
28	TOTAL SALES AND TRANSPORTATION SERVICE	$1,489,519	$1,494,622	$12,094	$1,506,716	$17,197	(X-Ref - Tab C-13, Schedule 25)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,798.7	$8.830	$457,371	15,692.9	$8.325	$130,649	1,682.7	$8.394	$14,124	$602,144
4	Schedule 2 - Small Commercial	17,866.8	8.972	160,297	5,791.0	8.449	48,931	716.5	8.554	6,129	215,357
5	Schedule 3 - Large Commercial	13,802.1	8.756	120,855	2,703.0	8.260	22,327	313.5	8.140	2,552	145,734
6	Schedules 1, 2 and 3	83,467.6		738,523	24,186.9		201,907	2,712.7		22,805	963,235
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,729.0	6.632	18,099	415.7	6.608	2,747	39.9	6.677	266	21,112
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,376.4		757,803	24,733.9		205,520	2,752.6		23,071	986,394
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,950.9	0.008	40	1,124.1	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.3	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,853.4		225	11,034.0		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,229.8		$758,028	35,767.9		$205,817	5,714.7		$23,308	$987,153

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000s)	Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.050	16	31
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.049	7	7
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,368.3	0.020	730	-	-	-	-	-	-	730
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,087.7		780	8,348.9		14	457.3		23	817
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,317.5		$758,808	44,116.8		$205,831	6,172.0		$23,331	$987,970

(X-Ref - Tab C-13, Schedule 12) , (X-Ref - Tab C-13, Schedule 4)

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Non-Bypass CORE AND NON-CORE**										
2	Core Sales										
3	Schedule 1 - Residential	51,350.2	$8.846	$454,251	15,555.0	$8.342	$129,766	1,673.7	$8.410	$14,076	$598,093
4	Schedule 2 - Small Commercial	18,027.1	8.991	162,072	5,851.0	8.471	49,566	725.0	8.580	6,221	217,859
5	Schedule 3 - Large Commercial	14,042.4	8.770	123,157	2,801.4	8.259	23,136	324.7	8.149	2,646	148,939
6	Schedules 1, 2 and 3	83,419.7		739,480	24,207.4		202,468	2,723.4		22,943	964,891
7											
8	Schedule 4 - Seasonal	87.8	6.701	588	96.8	6.622	641	-	-	-	1,229
9	Schedule 5 - General Firm	2,728.9	6.632	18,098	415.5	6.606	2,745	39.9	6.677	266	21,109
10											
11	Industrials										
12	Interruptible - Schedule 7	-	-	-	22.7	6.608	150	-	-	-	150
13											
14	N G V Fuel - Stations - Schedule 6	92.0	6.447	593	11.8	6.356	75	-	-	-	668
15											
16	Total Core Sales	86,328.4		758,759	24,754.2		206,079	2,763.3		23,209	988,047
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	-	-	-	5,514.3	0.017	94	2,588.9	0.081	210	304
20	- Interruptible Service	10,726.2	0.007	71	329.1	0.365	120	25.2	-	-	191
21	Schedule 23 - Large Commercial	4,974.0	0.008	40	1,144.2	0.016	18	59.0	0.080	5	63
22	Schedule 25 - Firm Service	9,356.0	0.008	75	3,318.8	0.016	53	269.3	0.080	22	150
23	Schedule 27 - Interruptible Service	4,820.0	0.008	39	747.7	0.016	12	19.7	-	-	51
24	Total T-Service	29,876.2		225	11,054.1		297	2,962.1		237	759
25	**Total Non-Bypass Sales and Transportation Service**										
26	**Cost of Gas Sold**	116,204.6		$758,984	35,808.3		$206,376	5,725.4		$23,446	$988,806

COST OF GAS BY RATE SCHEDULE - Summary by Service Area (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000s)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000s)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000s)	Total Cost of Gas ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	-	-	15	7,475.8	-	-	319.8	0.056	18	33
4	- Interruptible Service	-	-	-	-	-	-	-	-	-	-
5	Byron Creek (aka Fording Coal Mountain)	-	-	-	-	-	-	137.5	0.032	4	4
6	Burrard Thermal - Firm	1,719.4	0.020	35	-	-	-	-	-	-	35
7	TGVI - Firm	36,596.4	0.020	735	-	-	-	-	-	-	735
8	Schedule 23 - Large Commercial				-	-	-				-
9	Schedule 25 - Firm Service	-	-	-	873.1	0.016	14	-	-	-	14
10	Schedule 27 - Interruptible Service				-	-	-				-
11	**Total Bypass and Spec. Rates T-Svc**	38,315.8		785	8,348.9		14	457.3		22	821
12											
13	**Total Non-Bypass and Bypass Sales and Transportation Service**										
14	**Cost of Gas Sold**	154,520.4		$759,769	44,157.2		$206,390	6,182.7		$23,468	$989,627

(X-Ref - Tab C-13, Schedule 13) , (X-Ref - Tab C-13, Schedule 5)

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

			Revenue -- At Existing 2009 Rates --		Gross Margin -- At Existing 2009 Rates --		Effective Increase / (Decrease) 0.00% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000s)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000s)	Average Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	69,174.3	$13.196	$912,822	$4.491	$310,678	$0.000	$0	754,076	$13.196	$912,822
4	Schedule 2 - Small Commercial	24,374.3	12.208	297,556	3.372	82,200	-	0	76,536	12.208	297,556
5	Schedule 3 - Large Commercial	16,818.6	11.273	189,604	2.608	43,870	-	0	5,022	11.273	189,604
6	Total Schedules 1 , 2 and 3	110,367.2		1,399,982		436,747		0	835,633		1,399,982
7											
8	Schedule 4 - Seasonal Service	184.6	8.003	1,477	1.343	248	-	0	16	8.003	1,477
9	Schedule 5 - General Firm Service	3,184.6	8.796	28,012	2.167	6,901	-	0	281	8.796	28,012
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.542	194	1.938	44	-	0	2	8.542	194
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.062	1,044	3.628	377	-	0	32	10.062	1,044
15											
16	Total Core Sales	113,862.9		1,430,710		444,316		0	835,964		1,430,710
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.640	5,189	0.603	4,885	-	0	13	0.640	5,189
20	- Interruptible Service	11,080.5	0.837	9,270	0.819	9,079	-	0	22	0.837	9,270
21	Schedule 23 - Large Commercial	6,134.0	2.675	16,411	2.665	16,348	-	0	1,309	2.675	16,411
22	Schedule 25 - Firm Service	12,944.4	1.852	23,970	1.840	23,820	-	0	573	1.852	23,970
23	Schedule 27 - Interruptible Service	5,587.4	1.192	6,658	1.183	6,607	-	0	98	1.192	6,658
24											
25	Total T-Service	43,849.5		61,497		60,739		0	2,015		61,497
26											
27	Total Non-Bypass Sales & Transportation Service	157,712.4		$1,492,207		$505,055		$0	837,979		$1,492,207
28		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)				(X-Ref - Tab C-13, Schedule 2)			

TERASEN GAS INC.

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2010 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue -- At Existing 2009 Rates -- Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Gross Margin -- At Existing 2009 Rates -- Margin ($000s)	Increase / (Decrease) 0.00% of Margin $/GJ	Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.163	1,270	0.159	1,239	-	-	8	0.163	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.386	53	0.338	46	-	-	1	0.386	53
6	Burrard Thermal - Firm	1,719.4	5.814	9,996	5.794	9,962	-	-	1		9,996
7	TGVI - Firm	36,368.3	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.887	775	0.871	761	-	-	7	0.887	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	46,893.9		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	46,893.9		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,606.3		$1,504,300		$517,063		$0	837,998		$1,504,300
18		(X-Ref - Tab C-13, Schedule 14)		(X-Ref - Tab C-13, Schedule 16)				(X-Ref - Tab C-13, Schedule 2)			

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) 2.32% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Core Sales										
3	Schedule 1 - Residential	68,578.9	$13.236	$907,735	$4.515	$309,643	$0.105	$7,196	759,267	$13.341	$914,931
4	Schedule 2 - Small Commercial	24,603.1	12.227	300,831	3.372	82,972	0.078	1,928	77,252	12.305	302,759
5	Schedule 3 - Large Commercial	17,168.5	11.283	193,720	2.608	44,781	0.061	1,040	5,126	11.344	194,760
6	Total Schedules 1 , 2 and 3	110,350.5		1,402,286		437,395		10,164	841,644		1,412,450
7											
8	Schedule 4 - Seasonal Service	184.6	8.0030	1,477	1.3430	248	0.0330	6	16	8.036	1,483
9	Schedule 5 - General Firm Service	3,184.3	8.7960	28,009	2.1670	6,900	0.0510	161	281	8.847	28,170
10											
11	Industrials										
12	Schedule 7 - Interruptible	22.7	8.5420	194	1.9380	44	0.0440	1	2	8.586	195
13											
14	Schedule 6 - N G V Fuel - Stations	103.8	10.0620	1,044	3.6280	377	0.0870	9	32	10.149	1,053
15											
16	Total Core Sales	113,845.9		1,433,011		444,964		10,341	841,975		1,443,352
17											
18	Transportation Service										
19	Schedule 22 - Firm Service	8,103.2	0.6400	5,189	0.6030	4,885	0.0140	113	13	0.654	5,302
20	- Interruptible Service	11,080.5	0.8370	9,270	0.8190	9,079	0.0190	210	22	0.856	9,480
21	Schedule 23 - Large Commercial	6,177.2	2.6750	16,525	2.6650	16,462	0.0620	383	1,318	2.737	16,908
22	Schedule 25 - Firm Service	12,944.1	1.8520	23,969	1.8400	23,819	0.0430	554	573	1.895	24,523
23	Schedule 27 - Interruptible Service	5,587.4	1.1920	6,658	1.1830	6,607	0.0270	153	98	1.219	6,811
24											
25	Total T-Service	43,892.4		61,612		60,853		1,413	2,024		63,025
26											
27	Total Non-Bypass Sales & Transportation Service	157,738.3		$1,494,622		$505,817		$11,754	843,999		$1,506,376
28		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)			(X-Ref - Tab C-13, Schedule 3)				

REVENUE UNDER EXISTING 2009 RATES AND REVISED 2011 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2009 Rates -- Average $/GJ	Revenue -- At Existing 2009 Rates -- Revenue ($000)	Gross Margin -- At Existing 2009 Rates -- Average $/GJ	Gross Margin -- At Existing 2009 Rates -- Margin ($000s)	Increase / (Decrease) 2.32% of Margin $/GJ	Increase / (Decrease) of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	7,795.6	0.1630	1,270	0.1587	1,237	-	-	8	0.1630	1,270
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	137.5	0.3860	53	0.3543	49	-	-	1	0.3860	53
6	Burrard Thermal - Firm	1,719.4	5.8140	9,996	5.7936	9,962	-	-	1	5.8140	9,996
7	TGVI - Firm	36,596.4	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-		-		-		-	-	-	-
9	Schedule 25 - Firm Service	873.1	0.8870	775	0.8711	761	-	-	7	0.8870	775
10	Schedule 27 - Interruptible Service	-		-		-		-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	47,122.0		12,094		12,008		-	19		12,094
12											
13	Total Bypass Sales and										
14	Transportation Service	47,122.0		12,094		12,008		-	19		12,094
15											
16	TOTAL NON-BYPASS AND BYPASS SALES AND										
17	TRANSPORTATION SERVICE	204,860.3		$1,506,716		$517,825		$11,754	844,018		$1,518,470
18		(X-Ref - Tab C-13, Schedule 15)		(X-Ref - Tab C-13, Schedule 17)			(X-Ref - Tab C-13, Schedule 3)				

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OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,982	$3,014	$32	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,879	2,880	1	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	74	74	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,017	6,050	33	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,457	3,457	-	(X-Ref - Tab C-13, Schedule 2)
16					
17	SCP Third Party Revenue	12,819	12,819	-	(X-Ref - Tab C-13, Schedule 2)
18					
19	TGVI SAP Lease Income	129	129	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	16,405	16,405	-	
23					(X-Ref - Tab C-13, Schedule 12)
24	**Total Other Operating Revenue**	$22,422	$22,455	$33	(X-Ref - Tab C-13, Schedule 4)

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OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$2,987	$3,020	$33	(X-Ref - Tab C-13, Schedule 59)
4					
5	Connection Charge	2,905	2,907	2	(X-Ref - Tab C-13, Schedule 59)
6					
7	NSF Returned Cheque Charges	82	82	-	(X-Ref - Tab C-13, Schedule 59)
8					
9	Other Recoveries	76	76	-	(X-Ref - Tab C-13, Schedule 59)
10					
11	Total Other Utility Revenue	6,050	6,085	35	
12					
13	**Miscellaneous Revenue**				
14					
15	TGVI Wheeling Charge	3,455	3,455	-	(X-Ref - Tab C-13, Schedule 3)
16					
17	SCP Third Party Revenue	14,798	14,798	-	(X-Ref - Tab C-13, Schedule 3)
18					
19	TGVI SAP Lease Income	56	56	-	(X-Ref - Tab C-13, Schedule 59)
20					
21					
22	Total Miscellaneous	18,309	18,309	-	
23					(X-Ref - Tab C-13, Schedule 13)
24	**Total Other Operating Revenue**	$24,359	$24,394	$35	(X-Ref - Tab C-13, Schedule 5)

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Schedule 28

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	M&E Costs	$ 43,087	$ 45,496	$ 48,663	
2	COPE Costs	24,792	29,505	31,938	
3	IBEW Costs	22,301	24,870	26,559	
4					
5	**Labour Costs**	**90,179**	**99,871**	**107,160**	
6					
7	Vehicle Costs	4,626	3,111	3,084	
8	Employee Expenses	3,979	5,212	5,227	
9	Materials and Supplies	5,579	7,251	7,191	
10	Computer Costs	7,612	11,192	11,991	
11	Fees and Administration Costs	27,369	27,860	28,512	
12	Contractor Costs	58,251	60,112	60,052	
13	Facilities	11,717	13,973	14,318	
14	Recoveries & Revenue	(14,235)	(22,117)	(22,854)	
15					
16	**Non-Labour Costs**	**104,899**	**106,593**	**107,520**	
17					
18					
19	**Total Gross O&M Expenses**	**195,078**	**206,464**	**214,680**	
20					
21	Less: Vehicle Lease Reclass	(1,804)	-	-	
22	Less: Capitalized Overhead	(28,113)	(28,905)	(30,055)	
23					(X-Ref - Tab C-13, Schedule 4)
24	**Total O&M Expenses**	**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

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Schedule 29

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Distribution Supervision	100-11	$ 9,782	$ 10,331	$ 10,609	
2	Distribution Supervision Total	100-10	9,782	10,331	10,609	
3						
4	Operation Centre - Distribution	100-21	6,747	9,798	10,451	
5	Asset Management - Distribution	100-22	1,113	1,925	2,437	
6	Preventative Maintenance - Distribution	100-23	2,026	1,927	2,377	
7	Distribution Operations - General	100-24	4,720	5,096	5,512	
8	Emergency Management	100-25	6,582	5,240	5,488	
9	Distribution Operations Total	100-20	21,189	23,986	26,266	
10						
11	Distribution Corrective - Meters	100-31	1,176	1,433	1,524	
12	Distribution Corrective - Propane	100-32	5	5	5	
13	Distribution Corrective - Leak Repair	100-33	931	939	996	
14	Distribution Corrective - Stations	100-34	490	681	727	
15	Distribution Corrective - General	100-35	486	505	534	
16	Distribution Maintenance Total	100-30	3,089	3,562	3,785	
17						
18	**Distribution Total**	**100**	**34,060**	**37,879**	**40,660**	
19						
20	Transmission Supervision	200-11	2,448	3,079	3,161	
21	Transmission Supervision Total	200-10	2,448	3,079	3,161	
22						
23	Pipeline Operation	200-21	2,094	2,627	2,836	
24	Right of Way	200-22	1,407	1,282	1,345	
25	Compression	200-23	1,650	1,919	1,922	
26	Gas Control	200-24	2,264	2,896	3,105	
27	Transmission Pipeline Integrity Project (TPIP)	200-25	5,355	3,177	3,317	
28	Transmission Operations Total	200-20	12,771	11,902	12,525	
29						
30	Pipeline - Maintenance	200-31	167	189	194	
31	Compression - Maintenance	200-32	163	167	172	
32	TPIP - Maintenance	200-33	373	671	929	
33	Transmission Maintenance Total	200-30	702	1,027	1,295	
34						
35	**Transmission Total**	**200**	**15,921**	**16,008**	**16,980**	
36						
37	LNG Plant Operations	300-11	825	1,036	1,088	
38	LNG Plant Operations Total	300-10	825	1,036	1,088	
39	LNG Plant Maintenance	300-21	200	269	277	
40	LNG Plant Maintenance Total	300-20	200	269	277	
41						
42	**LNG Plant Total**	**300**	**1,025**	**1,305**	**1,365**	
43						
44	Measurement Operations	400-11	3,759	4,083	4,297	
45	Measurement Operations Total	400-10	3,759	4,083	4,297	
46						
47	Measurement Maintenance	400-21	1,804	2,208	2,334	
48	Measurement Maintenance Total	400-20	1,804	2,208	2,334	
49						
50	**Measurement Total**	**400**	**5,562**	**6,291**	**6,630**	

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OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000)

Line No.	Particulars	Reference	PROJECTION 2009	FORECAST 2010	FORECAST 2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Facilities Management	500-10	5,580	6,277	5,968	
2	Shops & Stores	500-20	3,699	4,018	4,152	
3	Operations Engineering	500-30	6,368	8,121	8,679	
4	Property Services	500-40	988	1,174	1,307	
5	System Integrity	500-50	2,040	2,393	2,492	
6	Environmental Health & Safety	500-60	1,490	2,352	2,504	
7	Operations Governance	500-70	1,515	1,692	1,800	
8						
9	**General Operations Total**	**500**	**21,679**	**26,025**	**26,903**	
10						
11	Energy Efficiency	600-10	$ 1,624	$ -	$ -	
12	Marketing - Supervision	600-20	1,208	621	634	
13	Corporate & Marketing Communications	600-30	2,574	3,593	3,673	
14	Marketing Planning & Development	600-40	749	655	669	
15	**Marketing Total**	**600**	**6,156**	**4,868**	**4,976**	
16						
17	Customer Care - Supervision	700-10	1,089	2,069	2,126	
18	Customer Contact - ABSU contract	700-20	47,127	48,470	49,422	
19	Bad Debt Management and Administration	700-30	6,112	5,874	6,018	
20	Customer Management & Sales	700-40	3,349	3,949	4,176	
21	**Customer Care Total**	**700**	**57,677**	**60,361**	**61,742**	
22						
23	Business & IT Services - Supervision	800-10	1,419	1,239	1,268	
24	Application Management	800-20	9,313	12,682	13,512	
25	Infrastructure Management	800-30	5,208	6,461	6,775	
26	Procurement Services	800-40	736	824	874	
27	**Business & IT Services Total**	**800**	**16,675**	**21,205**	**22,428**	
28						
29	Administration & General	900-11	3,229	(207)	(1,185)	
30	Insurance	900-12	4,725	4,410	4,631	
31	Finance and Regulatory Affairs	900-13	9,585	9,641	9,994	
32	Shared Services Agreement	900-14	3,541	2,116	1,899	
33	Corporate Administration Total	900-10	21,080	15,960	15,339	
34	Forecasting	900-20	1,022	1,632	1,672	
35	Public Affairs	900-30	1,375	1,731	1,762	
36	Business Development	900-40	1,416	3,123	3,183	
37	Human Resources	900-50	5,440	6,687	6,930	
38	Other Post Employment Benefits (OPEB)	900-60	5,991	3,389	4,111	
39	**Administration & General Total**	**900**	**36,324**	**32,522**	**32,996**	
40						
41	**Total Gross O&M Expenses**		**195,078**	**206,464**	**214,680**	
42						
43	Less: Vehicle Lease Reclass		(1,804)	-	-	
44	Less: Capitalized Overhead		(28,113)	(28,905)	(30,055)	
45						(X-Ref - Tab C-13, Schedule 4)
46	**Total O&M Expenses**		**$ 165,162**	**$ 177,559**	**$ 184,625**	(X-Ref - Tab C-13, Schedule 5)

* Note : Line 29 "Administration and General" expenses show a reduction of $1.0 million. The allocation of this $1.0 million reduction will be determined at a later date.

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Tab 13
Schedule 31

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Total Expenses	2010 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,187	$16,187	$16,187	$0	
4						
5	General, School and Other	33,006	33,006	33,006	-	
6						(X-Ref - Tab C-13, Schedule 4)
7	Total	$49,193	$49,193	$49,193	$0	(X-Ref - Tab C-13, Schedule 12)

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Schedule 32

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Total Expenses	2011 Revised Revenue, Total Expenses	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$16,067	$16,067	$16,067	$0	
4						
5	General, School and Other	34,144	34,144	34,144	-	
6						(X-Ref - Tab C-13, Schedule 5)
7	Total	$50,211	$50,211	$50,211	$0	(X-Ref - Tab C-13, Schedule 13)

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Tab 13
Schedule 33

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$113,009	$98,312	($14,697)	- Tab C-13, Schedule 49
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,849)	(6,850)	(1)	- Tab C-13, Schedule 52
6		106,160	91,462	(14,698)	
7					
8	Add: Removal Cost Provision	-	8,038	8,038	(X-Ref - Tab C-13, Schedule 4)
9					
10		106,160	99,500	($6,660)	
11			(X-Ref - Tab C-13, Schedule 37)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
15					
16		(2,364)	(2,569)	(205)	
17					(X-Ref - Tab C-13, Schedule 4)
18	TOTAL	$103,796	96,931	($6,865)	(X-Ref - Tab C-13, Schedule 12)

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Schedule 34

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation Provision**				
2					
3	Total Depreciation Expense	$115,696	$100,534	($15,162)	- Tab C-13, Schedule 51
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,674)	(6,677)	(3)	- Tab C-13, Schedule 53
6		109,022	93,857	(15,165)	
7					
8	Add: Removal Cost Provision	-	11,290	11,290	(X-Ref - Tab C-13, Schedule 5)
9					
10		109,022	105,147	(15,165)	
11			(X-Ref - Tab C-13, Schedule 38)		
12	**Amortization Expense**				
13					
14	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
15					
16		1,474	(5,269)	(6,743)	
17					(X-Ref - Tab C-13, Schedule 5)
18	TOTAL	$110,496	$99,878	($21,908)	(X-Ref - Tab C-13, Schedule 13)

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Schedule 35

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing Rates	2010 ----Revised Rates----- Revised Revenue	2010 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$185,254	$184,217	$0	$184,217	($1,037)	- Tab C-13, Schedule 4
3	Deduct - Interest on Debt	(110,056)	(109,062)	-	(109,062)	994	- Tab C-13, Schedule 10
4	Add- Non-Tax Ded. Expense (Net)	(1,864)	(2,069)	-	(2,069)	(205)	- Tab C-13, Schedule 37
5	Accounting Income After Tax	73,334	73,086	-	73,086	(248)	
6	Add (Deduct) - Timing Differences	5,999	(4,958)	-	(4,958)	(10,957)	- Tab C-13, Schedule 37
7	Taxable Income After Tax	79,333	68,128	-	68,128	(11,205)	
8	Taxable Income Adj - SCP Landscaping Deduction	-	(7,834)	-	(7,834)	(7,834)	
9	Taxable Income Adj - Tax on SCP Landscaping	-	2,233	-	2,233	2,233	
10	Adjusted Taxable Income After Tax	$79,333	$62,527	$0	$62,527	($16,806)	
11							
12		28.500%	28.500%	28.500%	28.500%	0.000%	
13	1 - Current Income Tax Rate	71.500%	71.500%	71.500%	71.500%	0.000%	
14							
15	Taxable Income	110,955	$87,450	$0	$87,450	($23,505)	
16							(X-Ref - Tab C-13, Schedule 4)
17	**Total Income Tax**	$31,622	$24,923	$0	$24,923	($6,699)	(X-Ref - Tab C-13, Schedule 12)

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing Rates	2011 ----Revised Rates----- Revised Revenue	2011 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$193,132	$184,295	$8,639	$192,934	($198)	- Tab C-13, Schedule 5
3	Deduct - Interest on Debt	(115,430)	(114,982)	-	(114,982)	448	- Tab C-13, Schedule 11
4	Add- Non-Tax Ded. Expense (Net)	1,974	(4,769)	-	(4,769)	(6,743)	- Tab C-13, Schedule 38
5	Accounting Income After Tax	79,676	64,544	8,639	73,183	(6,493)	
6	Add (Deduct) - Timing Differences	8,118	(5,053)	-	(5,053)	(13,171)	- Tab C-13, Schedule 38
7	Taxable Income After Tax	87,794	59,491	8,639	68,130	(19,664)	
8	Taxable Income Adjustment	-	-	-	-	-	
9	Taxable Income Adjustment	-	-	-	-	-	
10	Adjusted Taxable Income After Tax	$87,794	$59,491	$8,639	$68,130	($19,664)	
11							
12		26.500%	26.500%	26.500%	26.500%	0.000%	
13	1 - Current Income Tax Rate	73.500%	73.500%	73.500%	73.500%	0.000%	
14							
15	Taxable Income	119,448	$80,940	$11,754	$92,694	($26,754)	
16							(X-Ref - Tab C-13, Schedule 5)
17	**Total Income Tax**	$31,654	$21,449	$3,115	$24,564	($1,767)	(X-Ref - Tab C-13, Schedule 13)

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NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	($2,364)	($2,569)	($205)	- Tab C-13, Schedule 54
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	($1,864)	($2,069)	($205)	(X-Ref - Tab C-13, Schedule 35)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$106,160	99,500	($6,660)	- Tab C-13, Schedule 33
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	1,597	1,597	-	
15	Pension Expense	4,779	4,779	-	
16	OPEB Expense	5,320	5,320	-	
17	2010 Revenue Surplus (Net of Tax)	-	6,537	6,537	
18					
19	Deductions:				
20	Capital Cost Allowance	(98,544)	(96,990)	1,554	- Tab C-13, Schedule 39
21	Cumulative Eligible Capital Allowance	(1,001)	(1,001)	-	
22	Debt Issue Costs	(1,206)	(1,206)	-	
23	Vehicle Lease Payment	(3,149)	(3,149)	-	
24	Pension Contributions	(7,115)	(7,115)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,388)	(12,388)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(1,060)	(1,060)	-	
32					
33	Total Timing Differences	$5,999	($4,958)	($10,957)	(X-Ref - Tab C-13, Schedule 35)
					(X-Ref - Tab C-13, Schedule 6)

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Schedule 38

NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011	Change	Reference
	(1)	(2)	(3)	(4)	(5)
1	**ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME**				
2					
3	Amortization of Deferred Charges	$1,474	($5,269)	($6,743)	- Tab C-13, Schedule 55
4					
5	Non-tax Deductible Expenses	500	500	-	
6					
7	Total Permanent Differences	$1,974	($4,769)	($6,743)	(X-Ref - Tab C-13, Schedule 36)
8					(X-Ref - Tab C-13, Schedule 6)
9	**TIMING DIFFERENCE ADJUSTMENTS**				
10					
11	Addbacks:				
12	Depreciation & Removal Cost Provision	$109,022	105,147	($3,875)	- Tab C-13, Schedule 34
13	Amortization of Debt Issue Expenses	721	721	-	
14	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,029	2,029	-	
15	Pension Expense	5,704	5,704	-	
16	OPEB Expense	5,297	5,297	-	
17	2010 Revenue Surplus	-	-	-	
18					
19	Deductions:				
20	Capital Cost Allowance	(100,844)	(97,259)	3,585	- Tab C-13, Schedule 40
21	Cumulative Eligible Capital Allowance	(937)	(937)	-	
22	Debt Issue Costs	(1,003)	(1,003)	-	
23	Vehicle Lease Payment	(3,736)	(3,736)	-	
24	Pension Contributions	(7,322)	(7,322)	-	
25	OPEB Contributions	(503)	(503)	-	
26	Overheads Capitalized Expensed for Tax Purposes	-	(12,881)	(12,881)	
27	Overhead Capitalization Rate Change	-	-	-	
28	CCA Rate Change of 2007 & 2008	-	-	-	
29	Long Term Compensation	-	-	-	
30	Discounts on Debt Issue and Other	-	-	-	
31	Major Inspection Costs	(310)	(310)	-	
32					
33	Total Timing Differences	$8,118	($5,053)	($13,171)	(X-Ref - Tab C-13, Schedule 36)
					(X-Ref - Tab C-13, Schedule 7)

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CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Class	CCA Rate %	12/31/2009 UCC Balance	Adjustments	2010 Net Additions	2010 CCA	12/31/2010 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,190,923	($7,834)	$371	($47,331)	$1,136,129
2	1.3	6%	8,120	-	2,755	(570)	10,305
3	2	6%	164,165	-	-	(9,850)	154,315
4	3	5%	2,826	-	-	(141)	2,685
5	6	10%	206	-	-	(21)	185
6	7	15%	3,824	-	2,188	(738)	5,274
7	8	20%	15,184	-	2,441	(3,281)	14,344
8	10	30%	3,135	-	1,629	(1,185)	3,579
9	12	100%	-	3,087	11,604	(8,889)	5,802
10	13	Manual	2,682	-	167	(890)	1,959
11	14	Manual	2	-	-	(2)	-
12	17	8%	223	-	-	(18)	205
13	38	30%	225	-	30	(72)	183
14	39	25%	-	-	-	-	-
15	45	45%	891	-	-	(401)	490
16	47	8%	4,798	-	451	(402)	4,847
17	49	8%	65,970	-	12,903	(5,794)	73,079
18	50 / 52	55% / 100%	1,432	-	4,489	(5,276)	645
19	51	6%	168,386	-	67,541	(12,129)	223,798
20							
21		Total	$1,632,992	($4,747)	$106,569	($96,990)	$1,637,824
22						(X-Ref - Tab C-13, Schedule 37)	

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CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Class	CCA Rate %	12/31/2010 UCC Balance	Adjustments	2011 Net Additions	2011 CCA	12/31/2011 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$1,136,129	$0	$0	($45,445)	$1,090,684
2	1.3	6%	10,305	-	3,590	(726)	13,169
3	2	6%	154,315	-	-	(9,259)	145,056
4	3	5%	2,685	-	-	(134)	2,551
5	6	10%	185	-	-	(19)	166
6	7	15%	5,274	-	1,617	(912)	5,979
7	8	20%	14,344	-	2,214	(3,090)	13,468
8	10	30%	3,579	-	1,607	(1,315)	3,871
9	12	100%	5,802	-	11,000	(11,302)	5,500
10	13	Manual	1,959	-	51	(883)	1,127
11	14	Manual	-	-	-	-	-
12	17	8%	205	-	-	(17)	188
13	38	30%	183	-	30	(59)	154
14	39	25%	-	-	-	-	-
15	45	45%	490	-	-	(220)	270
16	47	8%	4,847	-	1,651	(454)	6,044
17	49	8%	73,079	-	6,024	(6,087)	73,016
18	50 / 52	55% / 100%	645	-	5,000	(1,729)	3,916
19	51	6%	223,798	-	72,667	(15,608)	280,857
20							
21		Total	$1,637,824	$0	$105,451	($97,259)	$1,646,016
22						(X-Ref - Tab C-13, Schedule 38)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
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Schedule 41

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Adjustments	2010 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,317,590	$3,315,365	$0	$3,315,365	($2,225)	- Tab C-13, Schedule 45
2	Adjustment - CPCNs	-				-	- Tab C-13, Schedule 43
3	Gas Plant in Service, Ending	3,449,336	3,453,394	-	3,453,394	4,058	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($779,187)	($780,174)	$0	($780,174)	($987)	- Tab C-13, Schedule 49
6	Accumulated Depreciation Ending - Plant	(840,835)	(835,365)	-	(835,365)	5,470	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($176,845)	($176,845)	$0	($176,845)	$0	- Tab C-13, Schedule 52
9	CIAC, Ending	(183,817)	(183,885)	-	(183,885)	(68)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$44,146	$44,146	$0	$44,146	$0	- Tab C-13, Schedule 52
12	Accumulated Amortization Ending - CIAC	47,061	47,062	-	47,062	1	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,438,725	$2,441,849	$0	$2,441,849	$3,125	
15							
16	Adjustment to 13-Month Average	13,537	13,537	-	13,537	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	(27,015)	(30,797)	-	(30,797)	(3,782)	- Tab C-13, Schedule 54
19	Cash Working Capital	(6,778)	(7,563)	-	(7,563)	(785)	- Tab C-13, Schedule 56
20	Other Working Capital (incl. Construction Advances)	103,439	103,439	-	103,439	-	- Tab C-13, Schedule 56
21	Future Income Taxes Regulatory Asset	284,455	284,455	-	284,455	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(284,455)	(284,455)	-	(284,455)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,648)	(1,648)	-	(1,648)	-	
24	**Utility Rate Base**	$2,535,887	$2,534,444	$0	$2,534,444	($1,442)	(X-Ref - Tab C-13, Schedule 10)

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Schedule 42

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 Adjustments	2011 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,449,336	$3,453,394	$0	$3,453,394	$4,058	- Tab C-13, Schedule 47
2	Adjustment - CPCNs	-				-	
3	Gas Plant in Service, Ending	3,535,828	3,538,378	-	3,538,378	2,550	- Tab C-13, Schedule 47
4							
5	Accumulated Depreciation Beginning - Plant	($840,835)	($835,365)	$0	($835,365)	$5,470	- Tab C-13, Schedule 51
6	Accumulated Depreciation Ending - Plant	(899,386)	(885,651)	-	(885,651)	13,735	- Tab C-13, Schedule 51
7							
8	CIAC, Beginning	($183,817)	($183,885)	$0	($183,885)	($68)	- Tab C-13, Schedule 53
9	CIAC, Ending	(194,646)	(194,753)	-	(194,753)	(107)	- Tab C-13, Schedule 53
10							
11	Accumulated Amortization Beginning - CIAC	$47,061	$47,062	$0	$47,062	$1	- Tab C-13, Schedule 53
12	Accumulated Amortization Ending - CIAC	50,241	50,245	-	50,245	4	- Tab C-13, Schedule 53
13							
14	Net Plant in Service, Mid-Year	$2,481,891	$2,494,713	$0	$2,494,713	$12,822	
15							
16	Adjustment to 13-Month Average	0	-	-	-	-	
17	Work in Progress, No AFUDC	15,627	15,627	-	15,627	-	
18	Unamortized Deferred Charges	10,347	6,770	-	6,770	(3,577)	- Tab C-13, Schedule 55
19	Cash Working Capital	(6,133)	(6,953)	6	(6,947)	(814)	- Tab C-13, Schedule 57
20	Other Working Capital (incl. Construction Advances)	120,091	120,091	-	120,091	-	- Tab C-13, Schedule 57
21	Future Income Taxes Regulatory Asset	292,155	292,155	-	292,155	-	- Tab C-13, Schedule 61
22	Future Income Taxes Regulatory Liability	(292,155)	(292,155)	-	(292,155)	-	- Tab C-13, Schedule 61
23	LILO Benefit	(1,482)	(1,482)	-	(1,482)	-	
24	**Utility Rate Base**	$2,620,341	$2,628,766	$6	$2,628,772	$8,431	(X-Ref - Tab C-13, Schedule 11)

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C Tab 13 Schedule 43

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2009 - 2011
($000)

Line No.	Particulars	Projected 2009	Forecast 2010	Forecast 2011	Reference
	(1)	(2)	(3)	(4)	(5)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4	Regular Capital Expenditures	85,425	93,511	93,597	
5	Gateway Project *	11,174	6,750	10,433	
6					
7	Total Regular Capital Expenditures	$ 96,599	$ 100,261	$ 104,030	
8					
9	Special Projects - CPCN's				
10	Vancouver LP Replacement	250	-	-	
11	Fraser River SBSA Rehabilitation	25,000	520	-	
12	Okanagan Reinforcement Project	500	500	500	
13	CCE CPCN	7,476	49,662	57,761	
14	Kootenay River Crossing	-	2,000	4,000	
15	Huntingdon Bypass	-	200	12,000	
16		0.00	0	0	
17	Total CPCN's	$ 33,226	$ 52,882	$ 74,261	
18					
19					
20	TOTAL CAPITAL EXPENDITURES	$ 129,825	$ 153,143	$ 178,291	
21					
22					
23	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
24					
25	Regular Capital				
26	Regular Capital Expenditures	96,599	100,260	104,030	
27	Add - Opening WIP	18,760	26,434	24,877	
28	Less - Opening WIP Adjustment	-	-	-	
29	Less - Closing WIP	(26,434)	(24,877)	(25,706)	
30	Capital Spares Inventory Reclassification	8,593	-	-	
31	Capital Vehicle Lease Addition	-	3,869	2,735	
32	Add - AFUDC	267	230	241	- Tab C-13, Schedule 45
33	Add - Overhead Capitalized	28,113	28,905	30,055	- Tab C-13, Schedule 47
34					
35	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 125,898	$ 134,821	$ 136,232	
36					
37	Special Projects - CPCN's				
38	CPCN Expenditures	33,226	52,882	74,261	
39	Add - Opening WIP	14,676	35,291	62,672	
40	Less - Closing WIP	(35,291)	(62,672)	(143,095)	
41	Less: Vancouver LP Removal costs (added to Accumulated Depreciation)	(394)	-	-	
42	Add - AFUDC	662	2,102	6,162	
43					- Tab C-13, Schedule 45
44	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$ 12,879	$ 27,603	-$ 0	- Tab C-13, Schedule 47
45		(X-Ref - Tab C-13, Schedule 41)			
46	TOTAL PLANT ADDITIONS	$ 138,777	$ 162,424	$ 136,232	
47					
48	Capital Vehicle Lease Opening Adjustment	-	26,103	-	- Tab C-13, Schedule 45
49					
50	TOTAL PLANT ADDITIONS and OPENING ADJUSTMENTS	$ 138,777	$ 188,527	$ 136,232	
51					
52					
53	* Spending associated with the Gateway Project is expected to be fully recovered via a contribution in aid of construction.				

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
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Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0	
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109	
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777	
5	178-00 Organization Expense	728	-	-	-	-	-	728	728	
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99	
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63	
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688	
10	461-00 Land Rights - Transmission	43,782	-	121	-	-	-	43,903	43,843	
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16	
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065	
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-	
14	402-01 Application Software - 12.5%	55,628	-	11,604	66	(8,954)	-	58,344	56,986	
15	402-02 Application Software - 20%	8,051	-	-	-	(1,847)	-	6,204	7,128	
16	TOTAL INTANGIBLE PLANT	111,006	-	11,725	66	(10,801)	-	111,996	111,501	
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31	
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475	
21	433 Manufact'd Gas - Equipment	425	-	425	-	-	-	850	638	
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663	
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53	
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309	
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928	
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885	
27	443 Gas Holders - Storage	16,655	-	519	4	-	-	17,178	16,917	
28	446 Compressor Equipment	-	-	-	-	-	-	-	-	
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-	
30	448 Purification Equipment	-	-	-	-	-	-	-	-	
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410	
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	47,834	-	944	4	-	-	48,782	48,308	
33										
34	**TRANSMISSION PLANT**									
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408	
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690	
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949	
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960	
39	465-00 Mains	736,398	27,349	21,172	79	(1,063)	(1,985)	781,950	772,849	*
40	465-00 Mains - Inspection	-	-	1,505	6	-	1,985	3,496	1,748	
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932	
42	466-00 Compressor Equipment	111,042	-	1,769	7	-	-	112,818	111,930	
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-	
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409	
45	467-10 Telemetering	8,494	-	106	-	-	-	8,600	8,547	
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39	
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346	
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-	
49	TOTAL TRANSMISSION PLANT	919,667	27,349	24,552	92	(1,063)	-	970,597	958,807	
50										
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.									

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 45

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	CPCN'S	2010 Additions	2010 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2010	Mid-year GPIS for Depreciation	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	**DISTRIBUTION PLANT**									
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418	
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697	
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107	
5	473-00 Services	640,145	254	31,160	-	(7,790)	-	663,769	652,084	**
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229	
7	474-00 House Regulators & Meter Installations	134,325	-	13,786	3	(11,032)	-	137,082	135,704	
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070	
9	475-00 Mains	844,063	-	21,883	31	(2,192)	-	863,785	853,924	
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704	
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571	
12	477-00 Measuring & Regulating Equipment	82,546	-	5,423	21	(817)	-	87,173	84,860	
13	477-00 Telemetering	5,916	-	256	1	(13)	-	6,160	6,038	
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163	
15	478-10 Meters	184,767	-	9,883	-	(7,907)	-	186,743	185,755	
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027	
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251	
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	
19	TOTAL DISTRIBUTION PLANT	2,030,999	254	82,391	56	(29,751)	-	2,083,949	2,057,601	
20										
21	**GENERAL PLANT & EQUIPMENT**									
22	480-00 Land in Fee Simple	21,905	-	126	-	-	-	22,031	21,968	
23	481-00 Land Rights	-	-	-	-	-	-	-	-	
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286	
26	- Masonry Buildings	83,527	-	2,228	-	-	-	85,755	84,641	
27	- Leasehold Improvement	473	-	167	1	-	-	641	557	
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-	
29	483-30 GP Office Equipment	4,480	-	87	-	(90)	-	4,477	4,479	
30	483-40 GP Furniture	19,730	-	509	1	(5)	-	20,235	19,983	
31	483-10 GP Computer Hardware	18,220	-	4,489	10	(6,245)	-	16,474	17,347	
32	483-20 GP Computer Software	853	-	-	-	(20)	-	833	843	
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-	
34	484-00 Transportation Equipment	2,279	-	1,629	-	-	-	3,908	3,094	
35	484-00 Vehicles - Leased	-	-	3,869	-	(2,321)	26,103	27,651	26,877	
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209	
37	485-20 Heavy Mobile Equipment	561	-	30	-	-	-	591	576	
38	486-00 Small Tools & Equipment	32,177	-	1,137	-	-	-	33,314	32,746	
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24	
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-	
42	- Telephone	11,239	-	504	-	(202)	-	11,541	11,390	
43	- Radio	4,896	-	204	-	-	-	5,100	4,998	
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-	
45	TOTAL GENERAL PLANT	205,859	-	14,979	12	(8,883)	26,103	238,070	235,016	
46										
47	**UNCLASSIFIED PLANT**									
48	499 Plant Suspense	-	-	-	-	-	-	-	-	
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-	
53										
54	TOTAL CAPITAL	$3,315,365	$27,603	$134,591	$230	($50,498)	$26,103	$3,453,394	$3,411,233	
55		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 49)		
56	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.							(X-Ref - Tab C-13, Schedule 8)		

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
GAS PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 46
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	$0	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	63	-	-	-	-	-	63	63
9	402-00 Other Intangible Plant	688	-	-	-	-	-	688	688
10	461-00 Land Rights - Transmission	43,903	-	124	-	-	-	44,027	43,965
11	461-10 Land Rights - Transmission - Byron Creek	16	-	-	-	-	-	16	16
12	471-00 Land Rights - Distribution	1,065	-	-	-	-	-	1,065	1,065
13	471-10 Land Rights - Distribution - Byron Creek	-	-	-	-	-	-	-	-
14	402-01 Application Software - 12.5%	58,344	-	11,000	66	(10,840)	-	58,570	58,457
15	402-02 Application Software - 20%	6,204	-	-	-	(1,147)	-	5,057	5,631
16	TOTAL INTANGIBLE PLANT	111,996	-	11,124	66	(11,987)	-	111,199	111,598
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	-	-	-	-	-	31	31
20	432 Manufact'd Gas - Struct. & Improvements	475	-	-	-	-	-	475	475
21	433 Manufact'd Gas - Equipment	850	-	-	-	-	-	850	850
22	434 Manufact'd Gas - Gas Holders	663	-	-	-	-	-	663	663
23	436 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	53	53
24	437 Manufact'd Gas - Measuring & Regulating Equipment	309	-	-	-	-	-	309	309
25	440/441 Land in Fee Simple	928	-	-	-	-	-	928	928
26	442 Structures & Improvements	4,885	-	-	-	-	-	4,885	4,885
27	443 Gas Holders - Storage	17,178	-	1,894	17	-	-	19,089	18,134
28	446 Compressor Equipment	-	-	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	-	-	-	-	-	-	-
30	448 Purification Equipment	-	-	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	-	-	-	-	-	23,410	23,410
32	TOTAL MANUFACTURED GAS / LOCAL STORAGE	48,782	-	1,894	17	-	-	50,693	49,738
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	-	-	-	-	-	7,408	7,408
36	462-00 Compressor Structures	14,690	-	-	-	-	-	14,690	14,690
37	463-00 Measuring Structures	4,949	-	-	-	-	-	4,949	4,949
38	464-00 Other Structures & Improvements	5,960	-	-	-	-	-	5,960	5,960
39	465-00 Mains	781,950	-	18,761	78	(942)	-	799,847	790,899
40	465-00 Mains - Inspection	3,496	-	444	2	-	-	3,942	3,719
41	465-10 Mains - Byron Creek	932	-	-	-	-	-	932	932
42	466-00 Compressor Equipment	112,818	-	1,851	8	-	-	114,677	113,748
43	466-00 Compressor Equipment - Overhaul	-	-	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	-	-	-	-	-	29,409	29,409
45	467-10 Telemetering	8,600	-	71	-	-	-	8,671	8,636
46	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	39	39
47	468-00 Communication Structures & Equipment	346	-	-	-	-	-	346	346
48	469-00 Other Transmission Equipment	-	-	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	970,597	-	21,127	88	(942)	-	990,870	980,734

TERASEN GAS INC. — Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 47

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2010	CPCN'S	2011 Additions	2011 AFUDC	Retirements	Transfers/ Recovery	Balance 12/31/2011	Mid-year GPIS for Depreciatior
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	$0	$0	$0	$0	$0	$3,418	$3,418
3	472-00 Structures & Improvements	14,697	-	-	-	-	-	14,697	14,697
4	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	107	107
5	473-00 Services	663,769	-	33,776	-	(8,444)	-	689,101	676,435
6	473-00 Services - LILO	43,229	-	-	-	-	-	43,229	43,229
7	474-00 House Regulators & Meter Installations	137,082	-	14,821	3	(11,859)	-	140,047	138,565
8	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	16,070	16,070
9	475-00 Mains	863,785	-	22,408	31	(2,244)	-	883,980	873,883
10	475-00 Mains - LILO	39,704	-	-	-	-	-	39,704	39,704
11	476-00 Compressor Equipment	571	-	-	-	-	-	571	571
12	477-00 Measuring & Regulating Equipment	87,173	-	5,560	24	(838)	-	91,919	89,546
13	477-00 Telemetering	6,160	-	258	1	(13)	-	6,406	6,283
14	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	163	163
15	478-10 Meters	186,743	-	10,391	-	(8,313)	-	188,821	187,782
16	478-11 Meters - LILO	10,027	-	-	-	-	-	10,027	10,027
17	478-20 Instruments	11,251	-	-	-	-	-	11,251	11,251
18	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION PLANT	2,083,949	-	87,214	59	(31,711)	-	2,139,511	2,111,730
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,031	-	129	-	-	-	22,160	22,096
23	481-00 Land Rights	-	-	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
25	- Frame Buildings	5,286	-	-	-	-	-	5,286	5,286
26	- Masonry Buildings	85,755	-	2,869	-	-	-	88,624	87,190
27	- Leasehold Improvement	641	-	51	-	-	-	692	667
28	Office Equipment & Furniture	-	-	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,477	-	60	-	(991)	-	3,546	4,012
30	483-40 GP Furniture	20,235	-	418	1	(1,230)	-	19,424	19,830
31	483-10 GP Computer Hardware	16,474	-	5,000	10	-	-	21,484	18,979
32	483-20 GP Computer Software	833	-	-	-	(198)	-	635	734
33	483-21 GP Computer Software	-	-	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,908	-	1,607	-	-	-	5,515	4,712
35	484-00 Vehicles - Leased	27,651	-	2,735	-	(1,641)	-	28,745	28,198
36	485-10 Heavy Work Equipment	209	-	-	-	-	-	209	209
37	485-20 Heavy Mobile Equipment	591	-	30	-	-	-	621	606
38	486-00 Small Tools & Equipment	33,314	-	1,105	-	-	-	34,419	33,867
39	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	24	24
40	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
41	488-00 Communications Equipment	-	-	-	-	-	-	-	-
42	- Telephone	11,541	-	464	-	(1,596)	-	10,409	10,975
43	- Radio	5,100	-	166	-	(954)	-	4,312	4,706
44	489-00 Other General Equipment	-	-	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	238,070	-	14,634	11	(6,610)	-	246,105	242,088
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	-	-	-	-	-	-	-
49	TOTAL UNCLASSIFIED PLANT	-	-	-	-	-	-	-	-
53									
54	TOTAL CAPITAL	$3,453,394	$0	$135,993	$241	($51,250)	$0	$3,538,378	$3,495,886
55		(X-Ref - Tab C-13, Schedule 9)	(X-Ref - Tab C-13, Schedule 43)					(X-Ref - Tab C-13, Schedule 9)	(X-Ref - Tab C-13, Schedule 51)

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 48

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	365	366
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	156	234
5	178-00 Organization Expense	728	1.00%	7	-	-	-	369	376
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	49	69
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	27	42
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	151	166
10	461-00 Land Rights - Transmission	43,843	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	-	19	$19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	56,986	12.50%	7,123	(4,264)	(8,954)	-	31,197	25,102
15	402-02 Application Software - 20%	7,128	20.00%	1,426	-	(1,847)	-	4,160	3,739
16	TOTAL INTANGIBLE PLANT	111,501		8,685	(4,264)	(10,801)	-	37,147	30,767
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	89	105
21	433 Manufact'd Gas - Equipment	638	6.30%	40	-	-	-	51	91
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	173	199
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	24	27
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	152	212
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,252	2,430
27	443 Gas Holders - Storage	16,917	2.18%	369	-	-	-	9,684	10,053
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	8,336	9,123
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	48,308		1,479	-	-	-	20,762	22,241
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,264	5,828
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,314	1,525
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,365	1,537
39	465-00 Mains	772,849 *	1.63%	12,597	-	(1,063)	-	182,855	194,389
40	465-00 Mains - INSPECTION	1,748	Term	691	-	-	-	-	691
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	794	841
42	466-00 Compressor Equipment	111,930	3.18%	3,559	-	-	-	35,074	38,633
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	6,266	8,381
45	467-10 Telemetering	8,547	1.33%	114	-	-	-	6,083	6,197
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	7	9
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	277	295
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	958,807		20,090	-	(1,063)	-	239,700	258,727
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 49

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision: 2010 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,231	3,760
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	16	21
5	473-00 Services	652,084 **	2.25%	14,672	-	(7,790)	-	78,219	85,101
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	16,079	17,030
7	474-00 House Regulators & Meter Installations	135,704	5.21%	7,070	-	(11,032)	-	(2,418)	(6,380)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,272	8,624
9	475-00 Mains	853,924	1.89%	16,139	-	(2,192)	-	235,807	249,754
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	15,605	16,399
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	403	546
12	477-00 Measuring & Regulating Equipment	84,860	5.72%	4,854	-	(817)	-	12,756	16,793
13	477-00 Telemetering	6,038	0.25%	15	-	(13)	-	6,386	6,388
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	185,755	5.31%	9,864	-	(7,907)	-	38,504	40,461
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,067	4,397
17	478-20 Instruments	11,251	4.03%	453	-	-	-	2,815	3,268
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,057,601		56,171	-	(29,751)	-	419,972	446,392
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,968	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	4,633	-	-	(3,059)	1,768
26	- Masonry Buildings	84,641	2.50%	2,116	1,048	-	-	7,996	11,160
27	- Leasehold Improvement	557	10.00%	56	218	-	-	88	362
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,479	6.67%	299	726	(90)	-	1,937	2,872
30	483-40 GP Furniture	19,983	5.00%	999	(824)	(5)	-	12,176	12,346
31	483-10 GP Computer Hardware	17,347	20.00%	3,469	(7,882)	(6,245)	-	17,871	7,213
32	483-20 GP Computer Software	843	20.00%	169	-	(20)	-	445	594
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	3,094	7.70%	238	(2,099)	-	-	2,832	971
35	484-00 Vehicles - Leased	26,877	Lease Term	2,464	14,066	(2,321)	-	-	14,209
36	485-10 Heavy Work Equipment	209	6.64%	14	39	-	-	73	126
37	485-20 Heavy Mobile Equipment	576	8.48%	49	424	-	-	(332)	141
38	486-00 Small Tools & Equipment	32,746	5.00%	1,637	570	-	-	14,380	16,587
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	6	8
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	11,390	6.67%	760	506	(202)	-	5,647	6,711
43	- Radio	4,998	6.67%	333	(696)	-	-	2,527	2,164
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	235,016		12,799	10,729	(8,883)	-	62,600	77,245
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,411,233		$99,224	$6,465	($50,498)	$0	$780,174	$835,365
52		(X-Ref - Tab C-13, Schedule 45)						(X-Ref - Tab C-13, Schedule 8)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(912)					
54									
55	**Net Depreciation Expense**			$98,312					
56				(X-Ref - Tab C-13, Schedule 33)					
57	** Adjusted for full year impact of 2009 Vancouver LP Replacement CPCN.								

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DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	1.00%	$0	$0	$0	$0	$0	$0
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	-	366	367
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	234	312
5	178-00 Organization Expense	728	1.00%	7	-	-	-	376	383
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	19.76%	20	-	-	-	69	89
8	402-00 Utility Plant Acquisition Adjustment	63	23.66%	15	-	-	-	42	57
9	402-00 Other Intangible Plant	688	2.14%	15	-	-	-	166	181
10	461-00 Land Rights - Transmission	43,965	0.00%	-	-	-	-	651	651
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%	-	-	-	$0	$19	19
12	471-00 Land Rights - Distribution	1,065	0.00%	-	-	-	-	2	2
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%	-	-	-	-	1	1
14	402-01 Application Software - 12.5%	58,457	12.50%	7,307	-	(10,840)	-	25,102	21,569
15	402-02 Application Software - 20%	5,631	20.00%	1,126	-	(1,147)	-	3,739	3,718
16	TOTAL INTANGIBLE PLANT	111,598		8,569	-	(11,987)	-	30,767	27,349
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	3.28%	16	-	-	-	105	121
21	433 Manufact'd Gas - Equipment	850	6.30%	54	-	-	-	91	145
22	434 Manufact'd Gas - Gas Holders	663	3.90%	26	-	-	-	199	225
23	436 Manufact'd Gas - Compressor Equipment	53	4.96%	3	-	-	-	27	30
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	19.50%	60	-	-	-	212	272
25	440/441 Land in Fee Simple and Land Rights	928	0.00%	-	-	-	-	1	1
26	442 Structures & Improvements	4,885	3.65%	178	-	-	-	2,430	2,608
27	443 Gas Holders - Storage	18,134	2.18%	395	-	-	-	10,053	10,448
28	446 Compressor Equipment	-	0.00%	-	-	-	-	-	-
29	447 Measuring & Regulating Equipment	-	0.00%	-	-	-	-	-	-
30	448 Purification Equipment	-	0.00%	-	-	-	-	-	-
31	449 Local Storage Equipment	23,410	3.36%	787	-	-	-	9,123	9,910
32	TOTAL MANUFACTURED GAS / LOCAL STORA(	49,738		1,519	-	-	-	22,241	23,760
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%	-	-	-	-	401	401
36	462-00 Compressor Structures	14,690	3.84%	564	-	-	-	5,828	6,392
37	463-00 Measuring Structures	4,949	4.27%	211	-	-	-	1,525	1,736
38	464-00 Other Structures & Improvements	5,960	2.88%	172	-	-	-	1,537	1,709
39	465-00 Mains	790,899	1.63%	12,892	-	(942)	-	194,389	206,339
40	465-00 Mains - INSPECTION	3,719	Term	553	-	-	-	691	1,244
41	465-10 Mains - Byron Creek	932	5.00%	47	-	-	-	841	888
42	466-00 Compressor Equipment	113,748	3.18%	3,617	-	-	-	38,633	42,250
43	466-00 Compressor Equipment - OVERHAUL	-	Term	-	-	-	-	-	-
44	467-00 Measuring & Regulating Equipment	29,409	7.19%	2,115	-	-	-	8,381	10,496
45	467-10 Telemetering	8,636	1.33%	115	-	-	-	6,197	6,312
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	4.01%	2	-	-	-	9	11
47	468-00 Communication Structures & Equipment	346	5.32%	18	-	-	-	295	313
48	469-00 Other Transmission Equipment	-	0.00%	-	-	-	-	-	-
49	TOTAL TRANSMISSION PLANT	980,734		20,306	-	(942)	-	258,727	278,091

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%	$0	$0	$0	$0	$30	$30
3	472-00 Structures & Improvements	14,697	3.60%	529	-	-	-	3,760	4,289
4	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	-	21	26
5	473-00 Services	676,435	2.25%	15,220	-	(8,444)	-	85,101	91,877
6	473-00 Services - LILO	43,229	2.20%	951	-	-	-	17,030	17,981
7	474-00 House Regulators & Meter Installations	138,565	5.21%	7,219	-	(11,859)	-	(6,380)	(11,020)
8	474-00 House Regulators & Meter Installations - LILO	16,070	2.19%	352	-	-	-	8,624	8,976
9	475-00 Mains	873,883	1.89%	16,516	-	(2,244)	-	249,754	264,026
10	475-00 Mains - LILO	39,704	2.00%	794	-	-	-	16,399	17,193
11	476-00 Compressor Equipment	571	25.04%	143	-	-	-	546	689
12	477-00 Measuring & Regulating Equipment	89,546	5.72%	5,122	-	(838)	-	16,793	21,077
13	477-00 Telemetering	6,283	0.25%	16	-	(13)	-	6,388	6,391
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%	-	-	-	-	200	200
15	478-10 Meters	187,782	5.31%	9,971	-	(8,313)	-	40,461	42,119
16	478-11 Meters - LILO	10,027	3.29%	330	-	-	-	4,397	4,727
17	478-20 Instruments	11,251	4.03%	453	-	-	-	3,268	3,721
18	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-	-
19		2,111,730		57,621	-	(31,711)	-	446,392	472,302
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,096	0.00%	-	-	-	-	13	13
23	481-00 Land Rights	-	0.00%	-	-	-	-	-	-
24	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-	-
25	- Frame Buildings	5,286	3.67%	194	-	-	-	1,768	1,962
26	- Masonry Buildings	87,190	2.50%	2,180	-	-	-	11,160	13,340
27	- Leasehold Improvement	667	10.00%	67	-	-	-	362	429
28	Office Equipment & Furniture	-	0.00%	-	-	-	-	-	-
29	483-30 GP Office Equipment	4,012	6.67%	268	-	(991)	-	2,872	2,149
30	483-40 GP Furniture	19,830	5.00%	991	-	(1,230)	-	12,346	12,107
31	483-10 GP Computer Hardware	18,979	20.00%	3,796	-	-	-	7,213	11,009
32	483-20 GP Computer Software	734	20.00%	147	-	(198)	-	594	543
33	483-21 GP Computer Software	-	0.00%	-	-	-	-	-	-
34	484-00 Transportation Equipment	4,712	7.70%	363	-	-	-	971	1,334
35	484-00 Vehicles - Leased	28,198	Lease Term	2,709	-	(1,641)	-	14,209	15,277
36	485-10 Heavy Work Equipment	209	6.64%	14	-	-	-	126	140
37	485-20 Heavy Mobile Equipment	606	8.48%	51	-	-	-	141	192
38	486-00 Small Tools & Equipment	33,867	5.00%	1,693	-	-	-	16,587	18,280
39	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	-	8	10
40	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-
41	488-00 Communications Equipment	-	0.00%	-	-	-	-	-	-
42	- Telephone	10,975	6.67%	732	-	(1,596)	-	6,711	5,847
43	- Radio	4,706	6.67%	314	-	(954)	-	2,164	1,524
44	489-00 Other General Equipment	-	0.00%	-	-	-	-	-	-
45	TOTAL GENERAL PLANT	242,088		13,521	-	(6,610)	-	77,245	84,156
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-	-	-	-	(7)	(7)
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	(7)	(7)
50									
51	TOTALS	$3,495,886		$101,536	$0	($51,250)	$0	$835,365	$885,651
52		(X-Ref - Tab C-13, Schedule 47)						(X-Ref - Tab C-13, Schedule 9)	
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects			(1,002)					
54									
55	**Net Depreciation Expense**			$100,534					
56				(X-Ref - Tab C-13, Schedule 34)					

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
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CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Balance 12/31/2009	Adjustment	2010 Additions	2010 Retirements	Balance 12/31/2010	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$141,389	$0	$6,424	$0	$147,813	
4							
5	Transmission Contributions	10,915	-	4,550	-	15,465	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	24,541	-	-	(3,934)	20,607	
11							
12	TOTAL Contributions	176,845	-	10,974	(3,934)	183,885	(X-Ref - Tab C-13, Schedule 8)
13							(X-Ref - Tab C-13, Schedule 41)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(32,291)	-	(3,765)	-	(36,056)	
19							
20	Transmission Contributions	-	-	(263)	-	(263)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(11,854)	-	(2,822)	3,934	(10,742)	
26							
27	TOTAL Amortization	(44,146)	-	(6,850)	3,934	(47,062)	(X-Ref - Tab C-13, Schedule 8)
28							(X-Ref - Tab C-13, Schedule 41)
29	**NET CONTRIBUTIONS**	$132,699	$0	$4,124	$0	$136,823	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 53

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Balance 12/31/2010	Adjustment	2011 Additions	2011 Retirements	Balance 12/31/2011	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$147,813	$0	$6,029	$0	$153,842	
4							
5	Transmission Contributions	15,465	-	8,333	-	23,798	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	20,607	-	-	(3,494)	17,113	
11							
12	TOTAL Contributions	183,885	-	14,362	(3,494)	194,753	(X-Ref - Tab C-13, Schedule 9)
13							(X-Ref - Tab C-13, Schedule 42)
14							
15							
16	**Amortization**						
17							
18	Distribution Contributions	(36,056)	-	(3,928)	-	(39,984)	
19							
20	Transmission Contributions	(263)	-	(391)	-	(654)	
21							
22	Others	(1)	-	-	-	(1)	
23							
24	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
25	- Infrastructure/Custom	(10,742)	-	(2,358)	3,494	(9,606)	
26							
27	TOTAL Amortization	(47,062)	-	(6,677)	3,494	(50,245)	(X-Ref - Tab C-13, Schedule 9)
28							(X-Ref - Tab C-13, Schedule 42)
29	**NET CONTRIBUTIONS**	$136,823	$0	$7,685	$0	$144,508	

TERASEN GAS INC.

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Section C
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APPENDIX A
to Order G-141-09
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UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Forecast Balance 12/31/2009	Opening Balance Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2010	Mid-Year Average 2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	($22,742.7)	$0.0	$31,808.0	($9,065.3)	$22,742.7	$0.0	$0.0	$0.0	$0.0	($11,371.4)
3	CCRA Interest	(895.9)		1,253.0	(357.1)	895.9	-	-	-	(0.0)	(448.0)
4	Midstream Cost Reconciliation Account (MCRA)	36,423.3		(50,941.7)	14,518.4	(36,423.3)	-	-	-	(0.0)	18,211.7
5	MCRA Interest	(1,779.2)		2,488.4	(709.2)	1,779.2	-	-	-	-	(889.6)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(13,165.6)		-	-	-	-	6,137.8	(1,749.3)	(8,777.1)	(10,971.4)
7	RSAM Interest	(38.4)		(5.3)	1.5	(3.8)	-	18.3	(5.2)	(29.1)	(33.8)
8	Revelstoke Propane Cost Deferral Account	(38.8)		54.3	(15.5)	38.8	-	-	-	(0.0)	(19.4)
9	SCP Mitigation Revenues Variance Account	(4,118.1)	(1,538.2)	-	-	-	1,723.2	-	-	(3,933.1)	(4,794.7)
10	SCP West to East Transmission	(1,538.2)	1,538.2	-	-	-	-	-	-	-	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	6,370.2		25,845.0	(7,365.8)	18,479.2	(1,012.0)	-	-	23,837.4	15,103.8
14	NGV Conversion Grants	136.9		77.5	(22.1)	55.4	(43.5)	-	-	148.8	142.9
15											
16	Non-Controllable Items										
17	Property Tax Deferral	(743.8)		-	-	-	398.1	-	-	(345.7)	(544.8)
18	Insurance Variance	(686.0)		-	-	-	686.0	-	-	-	(343.0)
19	Pension & OPEB Variance	(686.4)		-	-	-	686.4	-	-	-	(343.2)
20	BCUC Levies Variance	(262.0)		-	-	-	262.0	-	-	-	(131.0)
21	Interest Variance	(2,232.2)		-	-	-	633.9	-	-	(1,598.3)	(1,915.3)
22	Interest Variance - Funding benefits via Customer Deposits	214.2		-	-	-	(13.1)	-	-	201.1	207.7
23	Income Tax Rate Variance	(615.9)		-	-	-	205.3	-	-	(410.6)	(513.3)
24	Olympics Security Costs Deferral	522.8		2,651.6	(755.7)	1,895.9	-	-	-	2,418.7	1,470.8
25	IFRS Conversion Costs	399.5		265.3	(75.6)	189.7	-	-	-	589.2	494.4
26											
27	Cost of Current Applications										
28	2009 ROE & Cost of Capital Application	$441.0		$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$352.8	$396.9
29	2010-2011 Revenue Requirement Application	795.2		-	-	-	(397.6)	-	-	397.6	596.4
30	CCE CPCN Application	189.0		-	-	-	(37.8)	-	-	151.2	170.1
31											
32	Other										
33	IFRS Transitional Adjustments	-		(7,602.7)	-	(7,602.7)	-	-	-	(7,602.7)	(7,602.7)
34	OPEB Funding	(32,551.8)	32,551.8	-	-	-	-	-	-	-	(16,275.9)
35	Pension & OPEB Funding	-	(32,551.8)	20,476.7	-	20,476.7	-	-	-	(12,075.1)	(6,037.6)
36	2010 Revenue Surplus Deferral Account	-		(6,537.0)	-	(6,537.0)	-	-	-	(6,537.0)	(3,268.5)
37											
38	Residual Deferred Charges										
39	SCP Tax Reassessment	7,408.3		-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	1,442.9		(1,442.9)	-	(1,442.9)	-	-	-	-	-
41	Earnings Sharing Mechanism	(13,123.6)		3,372.0	(961.0)	2,411.0	-	6,168.7	(1,758.1)	(6,302.0)	(9,712.8)
42	CCT Assessment	(2.5)		-	-	-	2.5	-	-	-	(1.3)
43	Carbon Tax Implementation	(95.0)		-	-	-	95.0	-	-	-	(47.5)
44	TGS Amalgamation	132.0		-	-	-	(132.0)	-	-	-	66.0
45	TGS O&M Variance	352.0		-	-	-	(352.0)	-	-	-	176.0
46	Carbon Tax Cost of Service	(44.0)		-	-	-	44.0	-	-	(0.0)	(22.0)
47	OSC Certification Compliance	91.1		-	-	-	(91.1)	-	-	-	45.6
48	Bad Debt Allowance for Rates 14 & 14A	(140.2)	140.2	-	-	-	-	-	-	-	-
49											
50	Total Deferred Charges for Rate Base	($40,581.9)	$140.2	$21,762.2	($4,807.4)	$16,954.8	$2,569.1	$12,324.8	($3,512.6)	($12,105.6)	($30,796.6)
51							(X-Ref - Tab C-13, Schedule 33)			(X-Ref - Tab C-13, Schedule 8)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Forecast Balance 12/31/2010	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2011	Mid-Year Average 2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	CCRA Interest	(0.0)	-	-	-	-	-	-	(0.0)	-
4	Midstream Cost Reconciliation Account (MCRA)	(0.0)	-	-	-	-	-	-	(0.0)	-
5	MCRA Interest	-	-	-	-	-	-	-	-	-
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,777.1)	-	-	-	-	5,970.8	(1,582.3)	(4,388.6)	(6,582.9)
7	RSAM Interest	(29.1)	199.0	(52.7)	146.3	-	19.3	(5.1)	131.4	51.2
8	Revelstoke Propane Cost Deferral Account	(0.0)	-	-	-	-	-	-	(0.0)	-
9	SCP Mitigation Revenues Variance Account	(3,933.1)	-	-	-	1,735.9	-	-	(2,197.2)	(3,065.2)
10	SCP West to East Transmission	-	-	-	-	-	-	-	-	-
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	23,837.4	29,619.0	(7,849.0)	21,770.0	(2,524.9)	-	-	43,082.5	33,460.0
14	NGV Conversion Grants	148.8	255.0	(67.6)	187.4	(51.1)	-	-	285.1	217.0
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(345.7)	-	-	-	184.2	-	-	(161.5)	(253.6)
18	Insurance Variance	-	-	-	-	-	-	-	-	-
19	Pension & OPEB Variance	-	-	-	-	-	-	-	-	-
20	BCUC Levies Variance	-	-	-	-	-	-	-	-	-
21	Interest Variance	(1,598.3)	-	-	-	721.6	-	-	(876.7)	(1,237.5)
22	Interest Variance - Funding benefits via Customer Deposits	201.1	-	-	-	(13.1)	-	-	188.0	194.6
23	Income Tax Rate Variance	(410.6)	-	-	-	205.3	-	-	(205.3)	(308.0)
24	Olympics Security Costs Deferral	2,418.7	-	-	-	(806.2)	-	-	1,612.5	2,015.6
25	IFRS Conversion Costs	589.2	119.3	(31.6)	87.7	(196.4)	-	-	480.5	534.9
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$352.8	$0.0	$0.0	$0.0	($88.2)	$0.0	$0.0	$264.6	$308.7
29	2010-2011 Revenue Requirement Application	397.6	-	-	-	(397.6)	-	-	-	198.8
30	CCE CPCN Application	151.2	-	-	-	(37.8)	-	-	113.4	132.3
31										
32	Other									
33	IFRS Transitional Adjustments	(7,602.7)	68,819.0	-	68,819.0	-	-	-	61,216.3	26,806.8
34	OPEB Funding	-	-	-	-	-	-	-	-	-
35	Pension & OPEB Funding	(12,075.1)	(69,232.0)	-	(69,232.0)	-	-	-	(81,307.1)	(46,691.1)
36	2010 Revenue Surplus Deferral Account	(6,537.0)	-	-	-	6,537.0	-	-	-	(3,268.5)
37										
38	Residual Deferred Charges									
39	SCP Tax Reassessment	7,408.3	-	-	-	-	-	-	7,408.3	7,408.3
40	Deferred Service Line Installation Fee	-	-	-	-	-	-	-	-	-
41	Earnings Sharing Mechanism	(6,302.0)	1,686.0	(446.8)	1,239.2	-	6,888.2	(1,825.4)	-	(3,151.0)
42	CCT Assessment	-	-	-	-	-	-	-	-	-
43	Carbon Tax Implementation	-	-	-	-	-	-	-	-	-
44	TGS Amalgamation	-	-	-	-	-	-	-	-	-
45	TGS O&M Variance	-	-	-	-	-	-	-	-	-
46	Carbon Tax Cost of Service	(0.0)	-	-	-	-	-	-	(0.0)	-
47	OSC Certification Compliance	-	-	-	-	-	-	-	-	-
48	Bad Debt Allowance for Rates 14 & 14A	-	-	-	-	-	-	-	-	-
49										
50	Total Deferred Charges for Rate Base	($12,105.6)	$31,465.3	($8,447.7)	$23,017.6	$5,268.7	$12,878.3	($3,412.8)	$25,646.2	$6,770.4
51					(X-Ref - Tab C-13, Schedule 34)				(X-Ref - Tab C-13, Schedule 9)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 56

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	June 15, 2009 Application	2010 Existing 2009 Rates	2010 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$2,324	$1,539	$1,539	($785)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	-	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(5,940)	(5,940)	(5,940)	-	
10						
11	Withholdings From Employees	(3,162)	(3,162)	(3,162)	-	
12						
13	Subtotal	(6,778)	(7,563)	(7,563)	(785)	(X-Ref - Tab C-13, Schedule 8)
14						(X-Ref - Tab C-13, Schedule 41)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	-	
17	Transmission Line Pack Gas	2,413	2,413	2,413	-	
18	Gas in Storage	100,494	100,494	100,494	-	
19	Inventory - Materials & Supplies	1,202	1,202	1,202	-	
20						
21	Subtotal	103,439	103,439	103,439	0	(X-Ref - Tab C-13, Schedule 8)
22						(X-Ref - Tab C-13, Schedule 41)
23	Total	$96,661	$95,876	$95,876	($785)	

TERASEN GAS INC. Nov 5, 2009 NSP Agreement Section C
Tab 13
Schedule 57

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	June 15, 2009 Application	2011 Existing 2009 Rates	2011 Revised Revenue	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$3,186	$2,366	$2,372	($814)	- Tab C-13, Schedule 58
4						
5	Customer Deposits	-	0	-	0	
6						
7	Less - Funds Available:					
8						
9	Reserve for Bad Debts	(6,063)	(6,063)	(6,063)	0	
10						
11	Withholdings From Employees	(3,256)	(3,256)	(3,256)	0	
12						
13	Subtotal	(6,133)	(6,953)	(6,947)	(814)	(X-Ref - Tab C-13, Schedule 9)
14						(X-Ref - Tab C-13, Schedule 42)
15	**Other Working Capital Items**					
16	Construction Advances	(670)	(670)	(670)	0	
17	Transmission Line Pack Gas	4,731	4,731	4,731	-	
18	Gas in Storage	114,804	114,804	114,804	0	
19	Inventory - Materials & Supplies	1,226	1,226	1,226	0	
20						
21	Subtotal	120,091	120,091	120,091	0	(X-Ref - Tab C-13, Schedule 9)
22						(X-Ref - Tab C-13, Schedule 42)
23	Total	$113,958	$113,138	$113,144	($814)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Days	2009 Expenses	2009 Cash Working Capital	2010 Days	2010 Expenses	2010 Cash Working Capital	2011 Days	2011 Expenses	2011 Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
4	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
5											(X-Ref - Tab C-13, Schedule 56)
6	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,439,545	$2,366	(X-Ref - Tab C-13, Schedule 57)
7											
8											
9											
10	**CASHWORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	35.0			38.8			38.8			- Tab C-13, Schedule 59
13	Expense Lead Days	39.0			38.4			38.2			- Tab C-13, Schedule 60
14											(X-Ref - Tab C-13, Schedule 56)
15	Net Lead/(Lag) Days	(4.0)	$1,306,297	($14,316)	0.4	$1,404,291	$1,539	0.6	$1,443,164	$2,372	(X-Ref - Tab C-13, Schedule 57)
16											
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$0			$0			$6	
20											
21											
22											
23	Cash working capital = Col. 2 x Col. 3 / 365 days										

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

		2009			2010			2011			
Line No.	Particulars	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2009 Rates	Lag Days Service to Collection	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											- Tab C-13, Schedule 22
3	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
4	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,402,286	38.3	$53,763,147	
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	77,608	45.0	3,494,126	
6	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,044	41.7	43,552	
7											
8	Rates 22, Burrard, TGVI (Oth Rev), SCP (Oth Rev)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,031	42.3	1,864,247	
9											
10	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,524,969	38.8	59,165,072	
11				(X-Ref - Tab C-13, Schedule 2)			(X-Ref - Tab C-13, Schedule 3)				- Tab C-13, Schedule 26
12	Other Revenues										- Tab C-13, Schedule 27
13	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
14	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
15	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
16	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
17											
18											
19	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,531,110	38.8	$59,400,256	
20											
21											
22	**REVENUE, REVISED RATES**										
23											- Tab C-13, Schedule 22
24	Gas Sales and Transportation Service Revenue										- Tab C-13, Schedule 24
25	Residential and Commercial	$1,344,218	34.6	$46,509,939	$1,399,982	38.3	$53,675,914	$1,412,450	38.3	$54,152,948	
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	78,860	41.0	3,233,260	77,496	45.0	3,489,083	78,866	45.0	3,550,934	
27	NGV Fuel - Stations	1,076	38.7	41,657	1,044	41.7	43,552	1,053	41.7	43,927	
28											
29	Rates 22, Burrard, TGVI, SCP (Other)	40,576	37.8	1,533,765	42,054	42.5	1,788,524	44,354	42.4	1,878,846	
30											
31	Total Gas Sales	1,464,730	35.0	51,318,621	1,520,576	38.8	58,997,073	1,536,723	38.8	59,626,655	
32											- Tab C-13, Schedule 26
33	Other Revenues										- Tab C-13, Schedule 27
34	Late Payment Charges	2,878	26.7	76,843	3,014	38.3	115,444	3,020	38.3	115,681	
35	Returned Cheque Charges	84	31.8	2,671	82	38.3	3,140	82	38.3	3,140	
36	Connection Charges	2,926	37.3	109,140	2,880	38.3	110,315	2,907	38.3	111,323	
37	Other Utility Income	277	34.9	9,667	203	38.4	7,791	132	38.2	5,040	
38											
39											
40	Total Revenue	$1,470,895	35.0	$51,516,942	$1,526,755	38.8	$59,233,763	$1,542,864	38.8	$59,861,839	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009 Amount	2009 Lead Days Expense to Payment	2009 Dollar Days	2010 Amount	2010 Lead Days Expense to Payment	2010 Dollar Days	2011 Amount	2011 Lead Days Expense to Payment	2011 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Tab C-13, Schedule 4
4	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
5											- Tab C-13, Schedule 4
6	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
7											
8	Taxes Other Than Income										- Tab C-13, Schedule 31
9	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
10	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,292	420.3	4,325,728	
11	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
12	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,034	38.8	505,738	
13	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,101	37.1	1,599,047	
14	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	21,449	15.2	326,025	- Tab C-13, Schedule 6
15											- Tab C-13, Schedule 7
16	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,439,545	38.2	$55,049,590	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Tab C-13, Schedule 4
22	Expenses	$166,966	19.3	$3,222,444	$177,559	25.5	$4,527,755	$184,625	25.5	$4,707,938	- Tab C-13, Schedule 5
23											- Tab C-13, Schedule 4
24	Gas Purchases	930,677	40.7	37,878,554	987,970	40.2	39,716,394	989,627	40.2	39,783,006	- Tab C-13, Schedule 5
25											
26	Taxes Other Than Income										- Tab C-13, Schedule 31
27	Property Taxes	47,593	4.0	190,372	49,193	2.0	98,386	50,211	2.0	100,422	- Tab C-13, Schedule 32
28	Franchise Fees	10,044	430.0	4,318,920	10,259	420.3	4,311,858	10,376	420.3	4,361,033	
29	Carbon Tax	71,753	43.6	3,128,449	98,953	29.1	2,879,519	127,206	29.1	3,701,686	
30	GST - Net	12,520	7.2	90,131	12,997	38.8	504,291	13,136	38.8	509,665	
31	PST	40,647	43.6	1,772,209	42,437	37.1	1,574,413	43,420	37.1	1,610,882	
32	Income Tax	26,096	15.2	396,659	24,923	15.2	378,830	24,564	15.2	373,373	- Tab C-13, Schedule 6
33											- Tab C-13, Schedule 7
34	Total	$1,306,296	39.0	$50,997,738	$1,404,291	38.4	$53,991,446	$1,443,164	38.2	$55,148,005	

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2009 TO 2011
($000s)

Line No.	Particulars	2009	2010	2011
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	($2,447,020)	($2,535,462)	($2,625,708)
3	Less: Undepreciated Capital Cost	(1,712,991)	(1,760,477)	(1,853,515)
4		(734,029)	(774,985)	(772,193)
5	Weighted Average Future Tax Rate	25%	25%	25%
6		(184,037)	(194,075)	(193,048)
7				
8	Total FIT Liability- After Tax (PP&E)	(184,037)	(194,075)	(193,048)
9	Total FIT Liability- After Tax (Non-PP&E)	(24,298)	(23,948)	(27,038)
10	Total FIT Liability- After Tax	(208,335)	(218,023)	(220,086)
11				
12	Tax Gross Up	(69,713)	(72,839)	(73,362)
13				
14	FIT Liability/Asset - End of Year	(278,048)	(290,862)	(293,448)
15				
16	FIT Liability/Asset - Opening Balance	(278,048)	(278,048)	(290,862)
17				
18	FIT Liability/Asset - Mid Year	(278,048)	(284,455)	(292,155)
19		(X-Ref - Tab C-13, Schedule 8)	(X-Ref - Tab C-13, Schedule 9)	
20			(X-Ref - Tab C-13, Schedule 41)	
21	Note: * Excludes Land, Software CIAC, and WIP.		(X-Ref - Tab C-13, Schedule 42)	

TERASEN GAS INC.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Nov 5, 2009 NSP Agreement

Section C
Tab 13
Schedule 62

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2010 AT 2009 RATES							
2	Long-Term Debt	- Tab C-13, Schedule 64		$1,558,326	61.490%	6.870%	4.220%	$107,064
3	Unfunded Debt			88,809	3.500%	2.250%	0.080%	1,998
4	Common Equity			887,309	35.010%	8.483%	2.970%	75,270
5								
6		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.270%	$184,332
7								
8	2010 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,558,326	61.490%	6.870%	4.220%	$107,064
10	Unfunded Debt		$88,809					
11	Adjustment, Revised Rates		0	88,809	3.500%	2.250%	0.080%	1,998
12	Common Equity			887,309	35.010%	8.470%	2.970%	75,155
13								
14		- Tab C-13, Schedule 8		$2,534,444	100.000%		7.269%	$184,217
15							(X-Ref - Tab C-13, Schedule 4)	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
RETURN ON CAPITAL | Tab 13
FOR THE YEAR ENDING DECEMBER 31, 2011 | Schedule 63
($000s)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2011 At 2010 Rates							
2	Long-Term Debt	- Tab C-13, Schedule 65		$1,631,453	62.060%	6.836%	4.242%	$111,518
3	Unfunded Debt			76,982	2.930%	4.500%	0.132%	3,464
4	Common Equity			920,331	35.010%	7.529%	2.636%	69,292
5								
6		- Tab C-13, Schedule 9		$2,628,766	100.000%		7.010%	$184,274
7								
8	2011 REVISED RATES - FORECAST							
9	Long-Term Debt			$1,631,453	62.060%	6.836%	4.242%	$111,518
10	Unfunded Debt		$76,982					
11	Adjustment, Revised Rates		4	76,986	2.930%	4.500%	0.132%	3,464
12	Common Equity			920,333	35.010%	8.470%	2.965%	77,952
13								
14		- Tab C-13, Schedule 9		$2,628,772	100.000%		7.339%	$192,934
15							(X-Ref - Tab C-13, Schedule 5)	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 64

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense		Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	*	$65,598	12.054%	$66,453	$8,010	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228		155,046	10.461%	157,274	16,452	
3												
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290		147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915		148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663		148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784		119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303		247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389		247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000		99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000		99,000	5.318%	75,342	4,007	
12										-	-	
13												
14	LILO Obligations - Kelowna								5.905%	26,735	1,579	
15	LILO Obligations - Nelson								7.011%	4,258	299	
16	LILO Obligations - Vernon								8.150%	12,731	1,038	
17	LILO Obligations - Prince George								7.171%	32,685	2,344	
18	LILO Obligations - Creston								6.418%	3,098	199	
19												
20	Vehicle Lease Obligation								5.380%	12,740	685	
21												
22										$1,561,316	$107,269	
23												
24	Sub-Total									$1,561,316	$107,269	
25	Less - Fort Nelson Division Portion of Long Term Debt									(2,990)	(205)	
26	Total									$1,558,326	$107,064	
27									(X-Ref - Tab C-13, Schedule 10)	, (X-Ref - Tab C-13, Schedule 62)		
28	*Includes adjustment of $5,049 for BC Hydro Premium									Average Embedded Cost	6.870%	

TERASEN GAS INC.

Nov 5, 2009 NSP Agreement — Section C, Tab 13, Schedule 65

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$58,943	$855	$65,990 *	12.054%	$66,845	$8,057	
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610	
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897	
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970	
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714	
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168	
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,389	247,611	5.868%	250,000	14,670	
10	2009 Medium Term Debt Issue- Series 24 (includes replacement for Series E)	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627	
11	2009 Medium Term Debt Issue- Series 25	1-Apr-2010	1-Apr-2020	5.188%	100,000	1,000	99,000	5.318%	100,000	5,318	
12	2011 Medium Term Debt Issue- Series 26	1-Jul-2011	1-Jul-2021	5.650%	100,000	1,000	99,000	5.783%	50,411	2,915	
13											
14	LILO Obligations - Kelowna							5.919%	25,729	1,523	
15	LILO Obligations - Nelson							7.093%	4,110	292	
16	LILO Obligations - Vernon							8.242%	12,267	1,011	
17	LILO Obligations - Prince George							7.256%	31,571	2,291	
18	LILO Obligations - Creston							6.496%	2,996	195	
19											
20	Vehicle Lease Obligation							7.631%	13,455	1,027	
21											
22									$1,634,658	$111,737	
23											
24	Sub-Total								$1,634,658	$111,737	
25	Less - Fort Nelson Division Portion of Long Term Debt								(3,205)	(219)	
26	Total								$1,631,453	$111,518	
27								(X-Ref - Tab C-13, Schedule 11)	(X-Ref - Tab C-13, Schedule 63)		
28	*Includes adjustment of $7,772 for BC Hydro Premium								Average Embedded Cost	6.836%	

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
Tab 13
Schedule 66

GROSS MARGIN RECONCILIATION WITH 2010 RATES
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	2.961	69,174.3	$204,825	11.840	754,076	-1.20%	$105,858	-	-	$0	$310,683	$310,678	$5
4	Schedule 2 - Small Commercial	2.479	24,374.3	60,424	24.840	76,536	-4.54%	21,777	-	-	-	82,201.3	82,199.7	1.6
5	Schedule 3 - Large Commercial	2.136	16,818.6	35,925	132.520	5,022	-0.50%	7,945	-	-	-	43,869.8	43,869.5	0.3
6	Total Schedules 1 , 2 and 3		110,367.2	301,174		835,633		135,580		-	-	436,753.7	436,747.0	6.7
7														
8	Schedule 4 - Seasonal Service	0.762	184.6	141	439.000	16		83	-	-	-	224.1	247.9	(23.8)
9	Schedule 5 - General Firm Service	0.593	3,184.6	1,888	587.000	281		1,979	14.655	207	3,033	6,900.5	6,900.5	0.0
10														
11	Industrials													
12	Schedule 7 - Interruptible	0.990	22.7	22	880.000	2		21	-	-	-	43.6	44.0	(0.4)
13														
14	Schedule 6 - N G V Fuel - Stations	3.398	103.8	353	61.000	32		23	-	-	-	376.1	376.6	(0.5)
15														
16	Total Industrials		103.8	353		32		23		-	-	376.1	376.6	(0.5)
17														
18	Total Core Sales		113,862.9	303,578		835,964		137,666		207	3,033	444,298.0	444,316.0	(18.0)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.081	8,103.2	659.3	4,783.000	13		746	11.174	255.8	2,858.3	4,263.7	4,885.4	(621.7)
22	- Interruptible Service	0.739	11,080.5	8,190.3	3,742.000	22		988	-	14.5	-	9,178.2	9,078.6	99.5
23	Schedule 23 - Large Commercial	2.136	6,134.0	13,102	210.520	1,309		3,308	-	-	-	16,410.1	16,348.0	62.1
24	Schedule 25 - Firm Service	0.593	12,944.4	7,676	665.000	573		4,573	14.655	813	11,910	24,158.5	23,819.5	339.0
25	Schedule 27 - Interruptible Service	0.990	5,587.4	5,532	958.000	98		1,127	-	-	-	6,658.1	6,607.2	50.9
26														
27	Total T-Service		43,849.5	35,159		2,015		10,741		1,083	14,768	60,668.7	60,738.7	(70.0)
28														
29	Total Non-Bypass Sales & Transportation Service		157,712.4	338,737.2		837,979		148,407.4		1,290	17,800.9	504,966.7	505,054.7	(88.0)
30			(X-Ref - Tab C-13, Schedule 14)			(X-Ref - Tab C-13, Schedule 22)				(X-Ref - Tab C-13, Schedule 22 Columns 6 + 8, line 27)				

TERASEN GAS INC. | Nov 5, 2009 NSP Agreement | Section C
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Schedule 67

GROSS MARGIN RECONCILIATION WITH 2011 RATES
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line		Proposed Base Delivery Rate			Approved Basic Charge & Admin Fee				Proposed Demand Charge			Collected	Required	Margin
No.	Particulars	Rate	Terajoules	($000)	Rate	Customers	Adj Factor	($000)	Rate	Terajoules	($000)	Margin	Margin	Difference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**NON-BYPASS**													
2	Core Sales													
3	Schedule 1 - Residential	3.066	68,578.9	$210,263	11.840	759,267	-1.20%	$106,586	-	-	$0	316,848.9	316,838.8	10.1
4	Schedule 2 - Small Commercial	2.557	24,603.1	62,910	24.840	77,252	-4.54%	21,981	-	-	-	84,891.4	84,899.5	(8.1)
5	Schedule 3 - Large Commercial	2.197	17,168.5	37,719	132.520	5,126	-0.51%	8,110	-	-	-	45,828.8	45,820.9	7.9
6	Total Schedules 1 , 2 and 3		110,350.5	310,892		841,644		136,677		-	-	447,569.1	447,559.2	9.9
7														
8	Schedule 4 - Seasonal Service	0.790	184.6	146	256.080	16		49	-	-	-	194.5	253.9	(59.4)
9	Schedule 5 - General Firm Service	0.611	3,184.3	1,946	587.000	281		1,979	15.134	207	3,132	7,056.8	7,061.3	(4.5)
10														
11	Industrials													
12	Schedule 7 - Interruptible	1.018	22.7	23	880.000	2		21	-	-	-	44.2	45.0	(0.8)
13														
14	Schedule 6 - N G V Fuel - Stations	3.485	103.8	362	61.000	32		23	-	-	-	385.2	385.6	(0.4)
15														
16	Total Industrials		103.8	362		32		23		-	-	385.2	385.6	(0.4)
17														
18	Total Core Sales		113,845.9	313,345		841,975		138,728		207	3,132	455,249.7	455,305.0	(55.3)
19														
20	Transportation Service													
21	Schedule 22 - Firm Service	0.083	8,103.2	675	4,783.000	13		746	11.618	256	2,972	4,393.4	4,998.4	(605.0)
22	- Interruptible Service	0.757	11,080.5	8,384	3,742.000	22		988	1.702	15	25	9,396.3	9,288.6	107.7
23	Schedule 23 - Large Commercial	2.197	6,177.2	13,571	210.520	1,318		3,331	-	-	-	16,901.9	16,845.4	56.5
24	Schedule 25 - Firm Service	0.611	12,944.1	7,909	665.000	573		4,573	15.134	813	12,299	24,780.6	24,373.3	407.3
25	Schedule 27 - Interruptible Service	1.018	5,587.4	5,688	958.000	98		1,127	-	-	-	6,814.6	6,760.2	54.4
26														
27	Total T-Service		43,892.4	36,227		2,024		10,764		1,083	15,296	62,286.9	62,265.9	21.0
28														
29	Total Non-Bypass Sales & Transportation Service		157,738.3	349,572.8		843,999		149,492.1		1,290	18,427.5	517,536.6	517,570.9	(34.3)
30			(X-Ref - Tab C-13, Schedule 15)			(X-Ref - Tab C-13, Schedule 24)				(X-Ref - Tab C-13, Schedule 24 Columns 6 + 8, line 27)				

TERASEN GAS INC. June 15, 2009 Application Section C Tab 13 Schedule 68

EARNINGS SHARING CALCULATION - 2009
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Description	2009	Reference
	(1)	(2)	(3)
1	Utility rate base	$2,453,485	- Tab C-13, Schedule 74
2			
3	Common Equity Component (35.01%)	858,965	- Tab C-13, Schedule 75
4			
5			
6	Achieved ROE on Common Equity	11.41%	- Tab C-13, Schedule 75
7			
8	Authorized ROE on Common Equity	8.47%	
9			
10	ROE Surplus / (Deficit)	2.94%	
11			
12	After Tax Surplus Available for Sharing	$25,254	
13			
14			
15	Customers' 50% Share of Surplus (net-of-tax)	$12,627	(X-Ref - Tab C-13, Schedule 70)
16			
17			
18	**Customers' 50% Share of Surplus (pre-tax)**	**$18,038**	(X-Ref - Tab C-13, Schedule 70)

TERASEN GAS INC. June 15, 2009 Application Section C Tab 13 Schedule 69

END-OF-TERM CAPITAL INCENTIVE MECHANISM
FOR THE YEARS ENDING DECEMBER 31, 2004 TO 2011
($000s)

Line. No.		Particulars	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Projection 2009	2010	2011	2012	Reference
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	a)	Formula Base Capital Expenditure Spending (with Actual Customer adds)										
2		Customer Addition Driven CapEx	$24,283	$26,319	$21,896	$21,441	$20,133	$13,420				
3		Other Base Capital CapEx	67,361	69,090	70,588	72,278	73,595	74,850				
4		Total Base Capital Expenditures - Formula	91,644	95,409	92,484	93,719	93,728	88,270				
5												
6	b)	Actual Base Capital Expenditures										
7		Customer Addition Driven CapEx	$21,896	$25,194	$28,820	$28,903	$32,288	$25,428				
8		Other Base Capital CapEx	48,717	50,840	55,269	44,417	57,859	63,360				
9		Total Base Capital Expenditures - Actual	70,613	76,034	84,089	73,320	90,147	88,788				
10												
11	c)	Capital Incentive	$21,031	$19,375	$8,395	$20,399	$3,581	($518)				
12		Cumulative Capital Incentive for Phase-Out	$21,031	$40,406	$48,801	$69,200	$72,781	$72,263				
13												
14	d)	Capital Incentive @ 14%	$2,944	$5,657	$6,832	$9,688	$10,189	$10,117				
15												
16		Customer Portion (50/50 during term. Total benefit less Phase-Out after)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$6,745	$8,431	$10,117	
17												
18		Company Portion (50/50 during term. 2/3 & 1/3 Phase-Out in 2010 and 2011)	$1,472	$2,828	$3,416	$4,844	$5,095	$5,058	$3,372	$1,686	$0	
19												
20									(X-Ref - Tab C-13, Schedule 70)			

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 70

CALCULATION OF EARNING SHARING MECHANISM (RIDER 3)
FOR THE YEARS ENDING DECEMBER 31, 2010 TO 2011
($000s)

Line No.	Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	TOTAL Volumes (TJ)	2010 Margin ($000s)	2011 Margin ($000s)	TOTAL Margin ($000s)	2010 True-up & Res Amortization ($000s)	2010 & 2011 ESM Amortization ($000s)	2010 & 2011 Capital Incentive Amortization ($000s)	2010 ESM Unit Rider ($/GJ)	2011 ESM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Earnings Sharing Mechanism (ESM) Rider 3 Calculation**											
2												
3												
4	**Non-Bypass**											
5	Rate 1 - Residential	67,829.2	67,190.5	135,019.7	$ 306,966	$ 305,757	$612,724	($304)	($7,715)	$2,232	($0.040)	($0.046)
6	Rate 2 - Small Commercial	24,374.3	24,603.1	48,977.4	82,200	82,972	165,171	(83)	(2,081)	599	($0.029)	($0.034)
7	Rate 3 / 23 - Large Commercial	22,952.6	23,345.7	46,298.3	60,218	61,243	121,461	(60)	(1,529)	441	($0.023)	($0.027)
8	Rate 4 - Seasonal Service	184.6	184.6	369.2	248	248	496	-	(6)	2	($0.011)	($0.011)
9	Rate 5 / 25 - General Firm Service	15,565.0	15,470.1	31,035.1	30,469	30,413	60,882	(30)	(767)	222	($0.017)	($0.020)
10	Rate 6 - NGV	103.8	103.8	207.6	377	377	753	-	(9)	3	($0.024)	($0.033)
11	Rate 7 / 27 - Interruptible	5,197.7	5,186.1	10,383.8	6,258	6,247	12,505	(6)	(157)	45	($0.010)	($0.012)
12	Rate 22 - Large Industrial Transportation	11,579.4	11,560.2	23,139.6	9,332	9,318	18,651	(9)	(235)	68	($0.007)	($0.008)
13	Rate 22A - Inland	4,904.7	4,904.7	9,809.4	3,920	3,920	7,841	(4)	(99)	29	($0.007)	($0.008)
14	Rate 22B - Elkview Coal	646.1	646.1	1,292.2	112	112	224	-	(3)	1	$0.000	($0.002)
15	Rate 22B - All Other	1,856.3	1,856.3	3,712.6	1,037	1,037	2,075	(1)	(26)	8	($0.005)	($0.005)
16												
17	**Total Non-Bypass**	155,193.7	155,051.2	310,244.9	$501,138	$501,645	$1,002,783	($497)	($12,627)	$3,650 [1]		
18		(X-Ref - Tab C-13, Schedule 22; - Tab C-13, Schedule 24)										

19
20 Note 1:
21 Terasen Gas is projecting a 2009 return on equity of 11.41%, which is 2.94% higher than
22 the allowed ROE of 8.47%. Under the earnings sharing mechanism, Terasen Gas is to share
23 equally with its customers, earnings variances between the authorized level of earnings as
24 determined annually under the settlement and the actual earnings of the utility. Accordingly,
25 customer's portion of the 2009 earnings surplus is $18.038 million. The detailed calculations
26 for 2009 are as follows:
27
28 After Tax surplus available for sharing = $858.965 million x (11.41% - 8.47%) = $25,254 million
29 Customers' 50% share (Net-of-Tax) = $12.627 million
30 Customers' 50% share (Pre-Tax) = $18.038 million

Line		Amortization Period	2010 Pre-Tax	2010 Net-Of-Tax	2011 Pre-Tax	2011 Net-Of-Tax	Total Pre-Tax	Total Net-Of-Tax	
31									
32	The total amortization balance of $13.690 is made up of:								
33	2008 true-up ($12.029m per '07 A/Review, $12.739m per '08 A/Rpt)	2011	$710	$508	$0	$0	$710	$508	
34	Tax Adjustment on 2008 ESM True Up		(15)	(11)			(15)	(11)	
35			695	497	-	-	695	497	(Column 8, Line 17)
36									
37	2009 pre-tax Customers' 50% share	2010 and 2011	9,036	6,461	9,003	6,617	18,039	13,078	
38	Tax Adjustment on 2009 ESM		(190)	(136)	(429)	(315)	(618)	(451)	(Column 9, Line 17)
39			8,846	6,325	8,574	6,302	17,420	12,627	(X-Ref - Tab C-13, Schedule 68)
40									
41	2009 End Of Term Capital Incentive Mechanism	2010 and 2011	(3,372)	(2,411)	(1,686)	(1,239)	(5,058)	(3,650)	(Column 10, Line 17)
42									(X-Ref - Tab C-13, Schedule 69)
43	Total Balance - Refund to Customers in 2010 and 2011		$6,169	$4,411	$6,888	$5,063	$13,057	$9,474	(X-Ref - Tab C-13, Schedule 54; Schedule 55 line 39, columns 8 & 9)

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Particulars	2010 Volumes (TJ)	2011 Volumes (TJ)	2010 Amortization ($000s)	2011 Amortization ($000s)	2010 Amortization of RSAM Unit Rider ($/GJ)	2011 Amortization of RSAM Unit Rider ($/GJ)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
RSAM (Rider 5) Calculation						
Rate 1 - Residential	67,829.2	67,190.5			($0.053)	($0.052)
Rate 2 - Small Commercial	24,374.3	24,603.1			($0.053)	($0.052)
Rate 3 - Large Commercial	16,818.6	17,168.5			($0.053)	($0.052)
Rate 23 - Large Commercial Transportation	6,134.0	6,177.2			($0.053)	($0.052)
	115,156.1	115,139.3	($6,156)	($5,990) (1)		

(X-Ref - Tab C-13, Schedule 54; - Tab C-13, Schedule 55,sum of lines 6 & 7 and columns 8 & 9)

Note 1: RSAM Rider Change

Terasen Gas forecasts that there will be approximately -$5.6 million (net-of-tax) of RSAM additions by the end of 2009. After offsetting the 2009 RSAM Rider recovery, the RSAM account including interest is now projected to be a credit balance of $13,204,000 on a net-of-tax basis by the end of 2009. In accordance with the 2004-2009 Extended PBR Settlement, the RSAM balance is to be amortized over three years. Accordingly, the net-of-tax RSAM balance to be amortized in 2010 is a credit of $4,402,000. On a pre-tax basis, this amounts to $6,156,000 or a refund to the customer of $0.053/GJ, which is a $.054 reduction from the existing charge of $0.001/GJ. The corresponding 2011 refund to the customer is $0.052/GJ.

2010 Net-Of-Tax Amortization = 1/3 of Projected December 31, 2009 RSAM Balance
= 1/3 * ($-13,166 RSAM + $-38 RSAM Interest)
= 1/3 * $-13,204
= $-4,402 Net-of-tax amortization

2010 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 28.5%)
= $-6,156

2011 Net-of-Tax Amortization = 1/2 of Projected December 31, 2010 RSAM Balance
= 1/2 * ($-8,777 RSAM + $-29 RSAM Interest)
= 1/2 * $-8,806
= $-4,402 Net-of-tax amortization

2011 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate) + Amortization on Prior years' balances
= $-4,402 / (1 - 26.5%)
= $-5,990

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	2009 ----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	108,575	115,723	-	115,723	7,148	
3	Transportation	85,478	89,214	-	89,214	3,736	
4		194,053	204,937	-	204,937	10,884	
5							
6	Average Rate per GJ						
7	Sales	$14.892	$11.902	$0.000	$11.902	($2.990)	
8	Transportation	$0.848	$0.830	$0.000	$0.830	($0.018)	
9	Average	$8.706	$7.000	$0.000	$7.000	($1.706)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$1,591,039	$1,377,376	$0	$1,377,376	($213,663)	
13	- Increase / (Decrease)	25,852	-	-	-	(25,852)	
14	RSAM Revenue		(17,004)	-	(17,004)	(17,004)	
15	Transportation - Existing Rates	68,993	74,087	-	74,087	5,094	
16	- Increase / (Decrease)	3,535		-	-	(3,535)	
17	**Total**	1,689,419	1,434,459	-	1,434,459	(254,960)	
18							
19	Cost of Gas Sold (Including Gas Lost)	1,187,999	931,546	-	931,546	(256,453)	
20							
21	**Gross Margin**	501,420	502,913	-	502,913	1,493	
22							
23	Operation and Maintenance	173,138	165,162	-	165,162	(7,976)	- Tab C-13, Schedule 28
24	Vehicle Lease	1,804	1,804	-	1,804	-	- Tab C-13, Schedule 28
25	Property and Sundry Taxes	47,593	47,593	-	47,593	-	- Tab C-13, Schedule 31
26	Depreciation and Amortization	89,685	79,725	-	79,725	(9,960)	- Tab C-13, Schedule 33
27	Other Operating Revenue	(23,444)	(20,906)	-	(20,906)	2,538	- Tab C-13, Schedule 26
28		288,776	273,378	-	273,378	(15,398)	
29	Utility Income Before Income Taxes	212,644	229,535	(1)	229,535	16,891	
30							
31	Income Taxes	26,331	23,010	1	23,010	(3,321)	
32							
33	**EARNED RETURN**	$186,313	$206,525	$0	$206,525	$20,212	(X-Ref - Tab C-13, Schedule 73)
34							
35							
36	**UTILITY RATE BASE**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	- Tab C-13, Schedule 74
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	8.42%		8.42%	1.09%	

TERASEN GAS INC. June 15, 2009 Application Section C
Tab 13
Schedule 73

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	----Revised Rates----- Revised Revenue	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$186,313	$206,525	$0	$206,525	$20,212	- Tab C-13, Schedule 72
3	Deduct - Interest on Debt	(110,953)	(108,525)	-	(108,525)	2,428	- Tab C-13, Schedule 75
4	Add- Non-Tax Ded. Expense (Net)	328	428	-	428	100	
5							
6	Accounting Income After Tax	75,688	98,428	-	98,428	22,740	
7	Add (Deduct) - Timing Differences	(14,248)	(44,736)	-	(44,736)	(30,488)	- Tab C-13, Schedule 37
8							
9	Taxable Income After Tax	$61,440	$53,692	$0	$53,692	($7,748)	
10							
11		30.000%	30.000%	30.000%	30.000%	0.000%	
12	1 - Current Income Tax Rate	70.000%	70.000%	70.000%	70.000%	0.000%	
13							
14	Taxable Income	$87,771	$76,703	$0	$76,703	($11,068)	
15							
16	**Total Income Tax**	$26,331	$23,011	$0	$23,011	($3,320)	
17							

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	2009 APPROVED	2009 Existing 2009 Rates	Adjustments	Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$3,339,098	$3,215,664	$0	$3,215,664	($123,434)	
2	Adjustment - CPCNs	12,855	12,879	-	12,879	24	
3	Gas Plant in Service, Ending	3,442,274	3,317,590	-	3,317,590	(124,684)	- Tab C-13, Schedule 45
4							
5	Accumulated Depreciation Beginning - Plant	($808,588)	($743,486)	$0	($743,486)	$65,102	
6	Accumulated Depreciation Ending - Plant	(869,177)	(779,187)	-	(779,187)	89,990	- Tab C-13, Schedule 49
7							
8	CIAC, Beginning	($148,423)	($161,636)	$0	($161,636)	($13,213)	
9	CIAC, Ending	(146,828)	(176,845)	-	(176,845)	(30,017)	- Tab C-13, Schedule 52
10							
11	Accumulated Amortization Beginning - CIAC	$46,175	$45,381	$0	$45,381	($794)	
12	Accumulated Amortization Ending - CIAC	44,846	44,146	-	44,146	(700)	- Tab C-13, Schedule 52
13							
14	Net Plant in Service, Mid-Year	$2,456,116	$2,387,253	$0	$2,387,253	($68,863)	
15							
16							
17	Adjustment to 13-Month Average	-	(10,554)	-	(10,554)	(10,554)	
18	Work in Progress, No AFUDC	15,773	15,627	-	15,627	(146)	
19	Unamortized Deferred Charges*	(32,644)	(25,545)	-	(25,545)	7,100	- Tab C-13, Schedule 76
20	Cash Working Capital	(33,719)	(27,183)	-	(27,183)	6,536	- Tab C-13, Schedule 56
21	Other Working Capital (incl. Construction Advances)	138,198	115,701	-	115,701	(22,497)	- Tab C-13, Schedule 56
22	Future Income Taxes Regulatory Asset	-	278,048	-	278,048	278,048	- Tab C-13, Schedule 61
23	Future Income Taxes Regulatory Liability	(552)	(278,048)	-	(278,048)	(277,496)	- Tab C-13, Schedule 61
24	LILO Benefit	(1,814)	(1,814)	-	(1,814)	-	
25	**Utility Rate Base**	$2,541,358	$2,453,485	$0	$2,453,485	($87,873)	(X-Ref - Tab C-13, Schedule 68, Schedule 72,Schedule 75)

*Not equal to Schedule 8, column (2), line 19 because of differences in MCRA, CCRA and ESM balances for ESM calculation purposes

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Reference	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2009 RATES							
2	Long-Term Debt			$1,504,299	62.36%	6.959%	4.34%	
3	Unfunded Debt			90,221	2.63%	4.250%	0.11%	
4	Preference Shares			-	0.00%	0.000%	0.00%	
5	Common Equity			858,965	35.01%	11.740%	4.11%	
6								
7		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.56%	
8								
9	2009 REVISED RATES							
10	Long-Term Debt			$1,504,299	61.31%	6.959%	4.27%	$104,691
11	Unfunded Debt		$90,221					
12	Adjustment, Revised Rates		-	90,221	3.68%	4.250%	0.16%	3,834
13	Preference Shares			-	0.00%	0.000%	0.00%	-
14	Common Equity			858,965	35.01%	11.409%	3.99%	97,999
15		(X-Ref - Tab C-13, Schedule 72)						
16		- Tab C-13, Schedule 74		$2,453,485	100.00%		8.42%	$206,525

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2009
($000s)

Line No.	Particulars	Balance 12/31/2008	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2009	Mid-Year Average 2009
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Margin Related									
2	Commodity Cost Reconciliation Account (CCRA)	($23,164.7)	$602.9	($180.9)	$422.0	$0.0	$0.0	$0.0	($22,742.7)	($22,953.7)
3	CCRA Interest	(596.2)	(428.2)	128.5	(299.7)	-	-	-	(895.9)	(746.1)
4	Midstream Cost Reconciliation Account (MCRA)	(23,588.7)	85,731.4	(25,719.4)	60,012.0	-	-	-	36,423.3	6,417.3
5	MCRA Interest	(1,812.2)	47.2	(14.2)	33.0	-	-	-	(1,779.2)	(1,795.7)
6	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,917.2)	(7,902.9)	2,370.9	(5,532.0)	-	405.1	(121.5)	(13,165.6)	(10,541.4)
7	RSAM Interest	35.3	(133.2)	40.0	(93.2)	-	27.8	(8.3)	(38.4)	(1.6)
8	Revelstoke Propane Cost Deferral Account	(477.8)	627.1	(188.1)	439.0	-	-	-	(38.8)	(258.3)
9	SCP Mitigation Revenues Variance Account	(4,539.0)	(981.7)	324.5	(657.2)	1,078.1	-	-	(4,118.1)	(4,328.6)
10	SCP West to East Transmission	(1,658.0)	(376.1)	124.7	(251.4)	371.2	-	-	(1,538.2)	(1,598.1)
11										
12	Energy Policy Related									
13	Energy Efficiency & Conservation (EEC)	1,205.0	8,002.0	(2,400.6)	5,601.4	(436.2)	-	-	6,370.2	3,787.6
14	NGV Conversion Grants	124.0	80.0	(24.0)	56.0	(43.1)	-	-	136.9	130.5
15										
16	Non-Controllable Items									
17	Property Tax Deferral	(732.0)	(700.0)	210.0	(490.0)	478.2	-	-	(743.8)	(737.9)
18	Insurance Variance	(259.0)	(479.5)	143.9	(335.6)	(91.4)	-	-	(686.0)	(472.5)
19	Pension & OPEB Variance	207.0	(581.4)	-	(581.4)	(312.0)	-	-	(686.4)	(239.7)
20	BCUC Levies Variance	(295.0)	(383.7)	115.1	(268.6)	301.6	-	-	(262.0)	(278.5)
21	Interest Variance	(1,629.0)	(790.1)	237.0	(553.1)	(50.1)	-	-	(2,232.2)	(1,930.6)
22	Interest Variance - Funding benefits via Customer Deposits	161.0	76.9	(23.1)	53.8	(0.6)	-	-	214.2	187.6
24	Olympics Security Costs Deferral	-	746.9	(224.1)	522.8	-	-	-	522.8	261.4
25	IFRS Conversion Costs	98.0	430.7	(129.2)	301.5	-	-	-	399.5	248.8
26										
27	Cost of Current Applications									
28	2009 ROE & Cost of Capital Application	$0.0	$630.0	($189.0)	$441.0	$0.0	$0.0	$0.0	$441.0	$220.5
29	2010-2011 Revenue Requirement Application	55.0	1,057.5	(317.3)	740.2	-	-	-	795.2	425.1
30	CCE CPCN Application	-	270.0	(81.0)	189.0	-	-	-	189.0	94.5
31										-
32	Other									-
33	IFRS Transitional Adjustments	-	-	-	-	-	-	-	-	-
34	OPEB Funding	(28,644.0)	(5,582.6)	1,674.8	(3,907.8)	-	-	-	(32,551.8)	(30,597.9)
35	Pension & OPEB Funding	-	-	-	-	-	-	-	-	-
36										-
37	Residual Deferred Charges									-
38	SCP Tax Reassessment	7,292.8	165.0	(49.5)	115.5	-	-	-	7,408.3	7,350.6
39	Deferred Service Line Installation Fee	-	1,442.9	-	1,442.9	-	-	-	1,442.9	1,442.9
40	Earnings Sharing Mechanism	(9,879.1)	(18,748.0)	5,624.4	(13,123.6)	-	14,113.0	(4,233.9)	(13,123.6)	(11,501.4)
41	CCT Assessment	(16.0)	-	-	-	13.5	-	-	(2.5)	(9.3)
42	Carbon Tax Implementation	103.0	-	-	-	(198.0)	-	-	(95.0)	4.0
43	TGS Amalgamation	132.0	-	-	-	-	-	-	132.0	132.0
44	TGS O&M Variance	233.0	170.0	(51.0)	119.0	-	-	-	352.0	292.5
45	Carbon Tax Cost of Service	(384.0)	326.0	(97.8)	228.2	111.8	-	-	(44.0)	(214.0)
46	OSC Certification Compliance	90.0	110.7	(33.2)	77.5	(76.4)	-	-	91.1	90.6
47	Bad Debt Allowance for Rates 14 & 14A	(114.0)	(26.6)	0.4	(26.2)	-	-	-	(140.2)	(127.1)
48	2005 ROE Hearing	150.0	-	-	-	(150.0)	-	-	-	75.0
49	2006 LCT Elimination	14.0	-	-	-	(14.0)	-	-	-	7.0
50	NGV Compression Equipment Recovery	249.0	-	-	-	(249.0)	-	-	-	124.5
51	SCP PG&E Contract Cancellation	661.8	-	-	-	(661.8)	-	-	-	330.9
52										
53										
54	Total Deferred Charges for Rate Base	($94,895.0)	$63,403.2	($18,728.2)	$44,675.0	$71.8	$14,545.9	($4,363.7)	($39,966.0)	($66,709.1)
55										

Line No.							
56	Reconciliation with Mid Year Deferred Charges for ESM calculation:						
57							
58	Less:			Add:			
59	Projected Mid Year MCRA balance (+ interest)	4,621.6		Approved Mid Year MCRA balance (+ interest)	7,961.3		
60	Projected Mid Year CCRA balance (+ interest)	(23,699.8)		Approved Mid Year CCRA balance (+ interest)	(12,224.5)		
61	Projected Mid Year Revelstoke Propane balance	(258.3)		Approved Mid Year Revelstoke Propane balance	16.7		
62	Projected Mid Year ESM balance	(11,501.4)		Approved Mid Year Approved balance	3,916.2		
63	Projected Mid Year RSAM balance (+ interest)	(10,543.0)	(41,380.9)	Approved Mid Year RSAM balance (+ interest)	113.7	(216.6)	
64							
65				Net Mid-Year Reconciling items for ESM purposes			41,164.3
66				Mid Year Deferred Charges balance for ESM purposes			($25,544.8)
67							(X-Ref - Tab C-13, Schedule 74)
68							

Terasen Gas Inc. 2010-2011 Revenue Requirements Application
Negotiated Settlement Process
Issues of Particular Concern to the Commission Panel

In accordance with sections 3 and 9 of the Negotiated Settlement Process-Policy, Procedures and Guidelines, the Commission Panel has identified the following issues of particular concern that parties should be aware of during the negotiations:

1. EEC Program-TGI is to provide results of the programs approved by the EEC Decision and expectations for new programs before the Commission Panel will approve additional EEC program funding.

2. Natural Gas for Vehicles ("NGV")-if NGV is to proceed why should the natural gas ratepayer fund this initiative rather than Terasen's non-regulated businesses or the competitive market?

3. Biogas-to be reviewed by a CPCN which demonstrates market uptake of customers that are willing to pay the full cost.

4. International Financial Reporting Standards ("IFRS")-no IFRS impact in 2010.

5. 2010 Rate Changes-in the event that a 2010 rate reduction were to occur as a result of the negotiations, the current rates should remain unchanged and place the revenue surplus into a deferral account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability.

6. CPCN threshold-stay at $5million.

7. Unrealized losses in rate base-should some of these losses be to the shareholder? Parties should present a separate settlement package.

The
British Columbia
Public Interest
Advocacy Centre

208–1090 West Pender Street
Vancouver, BC V6E 2N7
Coast Salish Territory
Tel: (604) 687-3063 Fax: (604) 682-7896
email: bcpiac@bcpiac.com
http://www.bcpiac.com

Valerie Conrad	687-3017
Sarah Khan	687-4134
Eugene Kung	687-3006
James L. Quail	687-3034
Ros Salvador	488-1315
Leigha Worth	687-3044

Barristers & Solicitors

Peggy Lee
Article Student

Our file: 7432

November 12, 2009

VIA EMAIL

Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Re: Terasen Gas Inc. Revenue Requirements 2010-2011
Negotiated Settlement

This is to confirm that we are satisfied that the draft Settlement Agreement circulated by Mr. Thompson and Mr. Loski on November 5, 2009 accurately captures the consensus reached by the parties to the Negotiated Settlement Process in this proceeding, and that we have been instructed by our clients, BCOAPO et al., to endorse it.

Accordingly, we ask that the Commission incorporate it into a consent Order for the resolution of all issues in the Application.

Our only further comments, made here only "for the record" and in no way detracting from our clients' endorsement of the Settlement, concern the “Alternative Energy Solutions" addressed under heading 13 of the document. While we believe that the ultimately appropriate corporate and regulatory formats for these lines of business are subject-matters which may require eventual determination by the Commission, our clients are content with the treatment of these issues in the Settlement Agreement over its term, in that it provides a “firewall” to ensure that the utility’s natural gas distribution customers do not subsidize or otherwise contribute to these nascent programs through their rates.

Yours truly,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original in file signed by:

Jim Quail
Executive Director

cc: parties of record

OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0040

November 13, 2009

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Erica M. Hamilton,
Commission Secretary

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. ("Terasen") 2010 and 2011 Revenue Requirements and Delivery Rates Application, Project No. 3698562

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). We confirm that the CEC accepts the terms of the final version of the Negotiated Settlement Agreement on the above-noted Application circulated by Terasen on November 5, 2009 and have no comments on that draft.

The CEC thanks the Commission staff and facilitator, Terasen and the other customer representatives for their efforts during these negotiations.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: CEC
cc: Terasen
cc: Registered Intervenors

November 13, 2009

Mr. Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

RE: Negotiated Settlement Terasen Gas Inc. (TGI) Revenue Requirements Settlement 2010/2011

Dear Mr. Nakoneshny:

On November 5, 2009, TGI forwarded a Draft Agreement and requested that edits and comments be forwarded to TGI. Ministry of Energy, Mines and Petroleum Resources staff have reviewed the Draft Agreement and from a policy perspective, have an interest in 5 items:

11. Energy Efficiency and Conservation ("EEC") Funding for 2010
12. EEC Funding for 2011
13. Alternative Energy Solutions
14. Natural Gas for Vehicles
15. Biogas

Other components of the negotiated settlement such as capital cost structure, interest rates, depreciation rates, salvage values, etc., are outside the purview of the Ministry's interests in this agreement. However, we note that, in the future, Use per Customer Rates (8) and Industrial Demand Forecast (9) may be lower depending on the implementation of TGI's EEC programs.

The 2007 Energy Plan and Climate Action Plan, 2008 amendments to the *Utilities Commission Act,* Ministerial Order B.C. Reg. 326/2008, and the Ministry's involvement in the 2008/09 TGI/TGVI Energy Efficiency and Conservation Application indicate the Province's intent to require electric and natural gas utilities to pursue energy efficiency.

The Ministry is particularly pleased with the reallocation of funds for low income and rental housing programs to $2.4 million for 2010 and 2011. The Ministry also appreciates the increase in industrial energy efficiency program funding in 2011.

.../2

We believe there is great potential for a significant amount of this industrial funding to be applied collaboratively with existing demand side management programs at electric utilities, especially at BC Hydro, in order to minimize duplication of structural costs and to maximize energy savings benefits at industrial facilities.

Appropriate oversight of EEC funding is maintained through the TRC requirements and annual reporting to the Commission. As a result, the Ministry supports Option 12.1 (a) and (b) to maintain program continuity and effectiveness.

Alternative Energy Solutions is a new type of service that TGI proposes to offer to existing and new customers. Geo-exchange, solar-thermal and district energy systems offer the potential to reduce greenhouse gas emissions, and as such, the Ministry is encouraged that TGI is proposing to offer this new type of service.

The Ministry supports the expanded use of natural gas for vehicles (NGV) and biogass, and is encouraged that TGI intends to apply to the Commission for appropriate rates.

Sincerely,

Paul Wieringa
Executive Director
Renewable Energy and Energy Efficiency Branches
Ministry of Energy, Mines and Petroleum Resources
Telephone: 250-952-0243
Facsimile: 250-952-0258

From: Nakoneshny, Philip BCUC:EX
Sent: Friday, November 13, 2009 12:59 PM
To: Commission Secretary BCUC:EX
Subject: FW: Terasen Gas -Revenue Requirements-Negotiated Settlement

-----Original Message-----
From: Dave Newlands [mailto:dnewlands@telus.net]
Sent: Friday, November 13, 2009 9:40 AM
To: 'Al Kleinschmidt'; Brownell, Bob BCUC:EX; Bystrom, Chris; Chris Weafer; J. David Newlands; Roy, Diane; David Craig (dwcraig@allstream.net); Domingo, Yolanda BCUC:EX; Stout, Douglas; 'Eugene Kung'; 'Frederick Metcalfe'; 'Leigha Worth'; McMahon, Claudia BCUC:EX; Carman, Michelle; Nakoneshny, Philip BCUC:EX; 'Paul Cassidy'; Hill, Shawn; Loski, Tom; Wieringa, Paul EMPR:EX; Ghikas, Matt; Sue, Suzanne BCUC:EX; Thomson, Scott - TGI; James L. Quail (JimQuail@bcpiac.com)
Cc: Bernadet Mark SPO
Subject: Terasen Gas -Revenue Requirements-Negotiated Settlement

Philip Nakoneshny
Director of Rates and Finance
British Columbia Utilities Commission

Dear Philip

Terasen Gas Revenue Requirements Application-2010/2011
Negotiated Settlement

I write on behalf of Teck Coal.

Teck Coal participated in the Negotiated Settlement Process ("NSP"),facilitated by the Staff of the British Columbia Utilities Commission, and held in the offices of the Commission ,which commenced on October 21,2009.

Teck Coal in the negotiations took into consideration the 7 "Issues of Particular Concern to the Commission Panel ",as provided by the Commission Panel at the commencement of the negotiation.

Issue Number 5 stated " 2010 Rate Changes- in the event that a 2010 rate reduction were to occur as a result of the negotiations ,the current rates should remain unchanged and place the revenue surplus into a deferred account to apply against 2011 and future rate increases with a phase in amortization that strives for rate stability"

Teck Coal supports the Negotiated Settlement Agreement Package ("TGI NSP Agreement Package ") dated and circulated by Terasen Gas Inc incorporating a decrease of (1.73%) in the Fiscal Year commencing January 1,2010,previously an increase of 5.3%.and an increase of 3.93% in the Fiscal Year Commencing January 1,2011,previously an increase of 4.1% .

The Negotiated Settlement Agreement Package, incorporates ,amongst others,Issues of Particular Concern to the Commission Panel No. 5

Teck Coal recognizes and emphasizes that this Agreement is the product of compromise on the part of all Parties, yielding an overall package that the Parties consider to be fair, just and reasonable. The Parties agreed that any compromises resulting from this Agreement are without prejudice to the Parties¹ ability to take different positions after 2011 and without prejudice to the Parties right to intervene in any applications contemplated in or resulting from this Agreement.

Yours Truly

J.David Newlands

Cc Mark Bernadet ,General Manager ,Business Improvement,Teck Coal

PHILIP W. NAKONESHNY
DIRECTOR, RATES AND FINANCE
Philip.Nakoneshny@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

November 13, 2009

Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: Terasen Gas Inc.
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement
Letter of Comment

Commission staff participated in the settlement discussions that led to a Negotiated Settlement Agreement ("Settlement Agreement") being reached between Terasen Gas Inc. ("Terasen Gas") and the registered Intervenors (collectively, the "Parties") in accordance with the *Negotiated Settlement Process-Policy, Procedures and Guidelines, January 2001* ("NSP Guidelines"). Commission staff has informed the Parties that the agreements reached on certain issues were not supported by Commission staff and that Commission staff intended to submit a Letter of Comment in respect of those issues. The Parties agreed to Commission staff adopting that course.

There are three items in the Settlement Agreement that Commission staff do not support:

1. **Item 10-Inclusion of SCP Capacity in MCRA**

   Commission Order G-98-05 states that:
   "The Commission approves the debiting of the annual charge of $3.6 million (based on the monthly instalments) against the Midstream Cost Reconciliation Account, with an equal and offsetting amount to be credited to the delivery margin the revenue account for a limited period as a unique and unusual transaction in the circumstances of the SCP and the termination of the BC Hydro TSA. The debiting and the crediting will commence on either November 1, 2005 or January 1, 2006, as consistent with the amount of the BC Hydro/Terasen Inc. TSA revenue that Terasen Gas forecast in its Annual Review submission for 2005 and will end on the earlier of the November 1, 2010 or such other date as the Commission may determine."

   The Settlement Agreement continues to include the annual charge of $3.6 million against the MCRA with an offsetting credit to the delivery margin. In Commission staff's view, extending this treatment beyond November 1, 2010 as contemplated by Order G-98-05 requires a determination by the Commission Panel.

Commission staff accepts that such determination will occur if the Commission Panel approves the Settlement Agreement.

2. Item 13-Alternative Energy Solutions

Terasen Gas added 9 enhanced sales and business development staff in 2009 estimated to cost $1.35 million and proposes increases of $3.0 million in 2010 for an additional 10 enhanced sales and business development staff including $1.1 million for consultants and studies and a further $0.6 million in 2011 for 4 enhanced sales and business development staff (BCUC IR 1.72.2 and IR 2.96.2 to 2.96.4; IR 1.114.7). The number of customers are expected to increase between 1.0 to 1.1 percent from 2009 to 2011, but the level of spending in Customer Solutions and Services increases by 17 percent, 27 percent and 8 percent respectively from 2009 to 2011 (BCUC IR 1.96.3).

The New Energy Solutions Deferral Account is to capture direct costs, sales and marketing O&M and other development costs by timesheets or other direct charge and an overhead allocation. In Commission staff's view, due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions. The use of timesheets, direct charges and overhead allocations may result in a proper reallocation of costs from the gas utility to the New Energy Solutions Deferral Account.

The down time or idle time that will likely be experienced while the Alternative Energy is being marketed may not be captured by the timesheet allocation and could remain as a cost to the gas utility. In Commission staff's view, it would be preferable to directly charge the fully loaded cost of the additional enhanced sales and business development staff and the costs of consultants and studies to the New Energy Solutions Deferral Account to avoid any of these costs being borne by natural gas customers.

If Terasen Gas is able to demonstrate that the use of timesheets, direct charges and overhead allocations would result in none of the costs that are incurred for Alternative Energy Solutions including down time and the costs of consultants and studies to be borne by gas customers, then Commission staff's concern is addressed.

3. Item 14-Natural Gas for Vehicles ("NGV")

Terasen Gas proposes to treat as general O&M, rather than track separately, NGV marketing and project development costs incurred prior to signing a contract with a customer for compression and refuelling service (BCUC IR 1.21.1).

Commission staff attempted to obtain information on the NGV marketing costs that are currently incurred through information requests, but were unsuccessful. In Commission staff's view, information on the incremental marketing costs being incurred will be required if Terasen Gas, during 2010 and 2011, applies

…/3

for approval of Rate Schedule 6 C NGV Compression and Refuelling Service and 6A NGV Refuelling Service , including recovery of the incremental marketing costs, and the Commission is to review the applications on a case-by-case basis as contemplated in the Settlement Agreement.

Yours truly,

Original Signed by

Philip W. Nakoneshny
Director, Rates and Finance

Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

November 13, 2009

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Philip Nakoneshny, Director, Rates and Finance

Dear Mr. Nakoneshny:

Re: Terasen Gas Inc. ("Terasen Gas")
2010 and 2011 Revenue Requirements Application
Negotiated Settlement Agreement

On June 15, 2009, Terasen Gas filed its 2010 and 2011 Revenue Requirements Application, which was supplemented by a filing on July 9, 2009 and amended by filings on August 14 and September 18, 2009 (the "Application").

In accordance with Commission Order No. G-76-09 issued on June 19, 2009, a Workshop was held on July 6, 2009 for a review of the Application, a Procedural Conference was held on July 15, 2009, and Terasen Gas responded to two rounds of Information Requests. In accordance with Commission Order No. G-89-09 issued on July 20, 2009, a second Procedural Conference was held on September 25, 2009 and on October 2, 2009, the Commission issued Order G-119-09 establishing a Negotiated Settlement Process ("NSP") for the Application. In accordance with Order No. G-120-09, the NSP commenced on Wednesday, October 21, 2009 and concluded on Wednesday, November 4, 2009.

Terasen Gas has reviewed the attached settlement documents, including the Negotiated Settlement Agreement and associated financial schedules (collectively the "Negotiated Settlement") arising from the NSP. Terasen Gas recognizes the Negotiated Settlement as being the product of good faith compromises among parties with diverse interests in the issues raised by the Application. The Parties have expressly considered the Commission Panel's Issues. In fulfilling their role pursuant to the Commission's Negotiated Settlement Process Policy, Procedures and Guidelines (the "Guidelines"), Commission Staff made additional information available to the parties which they believed was in the public interest. The parties considered all such information in reaching the compromise Settlement Agreement and Terasen Gas considers the resulting Negotiated Settlement to be fair, just and reasonable. As the Negotiated Settlement represents compromises among the parties and an overall balance of interests, Terasen Gas stresses that the Negotiated Settlement should be considered as a package, with no part being severed unless otherwise stated in the Agreement. On that basis, Terasen Gas accepts the Negotiated Settlement.

Commission Staff have provided written comment on the NSP, and TGI responds to those comments below.

Terasen Gas

Inclusion of Southern Crossing Pipeline ("SCP") Capacity in the Midstream Cost Reconciliation Account ("MCRA"): TGI notes for reference that the evidence on the inclusion of the SCP costs in the MCRA is found in the Application on pages 314 to 315 and its response to BCUC IRs 1.68.1 and 2.92.1-7. The result of taking the approach in the Agreement is a lower delivery rate, all else equal, with an offsetting charge to the MCRA.

Alternative Energy Solutions (Geothermal/District Energy Systems and Solar Thermal): Staff's position on this issue turns on its view that, *"due to the modest growth in customer additions from 2009 to 2011, the additional enhanced sales and business development staff were primarily hired in 2009 to 2011 to develop and market Alternative Energy Solutions."* While that may be Staff's position, it is at odds with TGI's evidence. Staff's conclusion appears to rest on the notion that TGI could not truly require additional staff for marketing if there is only modest growth in customer additions, i.e. that there is a linear correlation between marketing effort and customer additions. TGI's evidence was that the competitive factors facing the gas business mean that it is necessary to invest more to maintain and grow the business, including the gas business.

Staff also identifies an issue relating to overhead allocation to the alternative energy class of service, so as to ensure gas customers are not bearing costs attributable to the pursuit of geothermal, solar thermal and district energy systems. The cost allocation methodology outlined in the Agreement is structured to avoid cross subsidization by gas customers. The Agreement contemplates a $500,000 annual overhead allocation to alternative energy solutions, and a corresponding reduction in overhead allocated to gas customers. This is a direct benefit to gas customers. As a point of comparison, the allocation of overhead to alternative energy solutions is approximately two times the allocation to Terasen Gas (Whistler) Inc., suggesting that the issue of overhead allocation is addressed adequately. The risk of non-recovery lies with TGI's shareholder, not gas customers. Notably, the gas customers themselves have endorsed the Agreement.

NGV Marketing Costs: TGI notes that it has an existing NGV tariff and the amount of NGV marketing costs in the revenue requirements for 2010 and 2011 is very modest (see TGI's responses to BCUC IR 1.21.2 (last paragraph) and BCUC IR 2.96.2). Issues relating to NGV have been deferred by the terms of the Settlement Agreement. TGI respectfully submits that there is no need for the Panel to address Staff's issue at this time.

TGI wishes to make one final comment relating to our procedural concerns regarding the publication of Staff's comments. Commission Staff unquestionably plays an important role during the confidential settlement discussions in providing information and assisting the parties, and providing a perspective regarding their view on the public interest. That role is one sanctioned by, and described in, the Commission's Guidelines. However, under the Guidelines (at page 8) Commission Staff is precluded from, "endorsing a particular position". TGI therefore questions whether the letter provided by Commission Staff is consistent with the Guidelines.

Terasen Gas

TGI respectfully submits that the requirement for the Commission Staff not to take positions on issues makes good sense. Commission Staff is not a party to the resulting Agreement; rather, the Negotiated Settlement Agreement is simply an agreement among intervenors and the applicant that a certain outcome is acceptable to them and should be jointly submitted for consideration by the Panel. In this case, the Agreement is clear that the Parties, having fully considered the information provided by Staff during the course of the NSP, have reached a compromise agreement that they consider to be in all respects fair, just and reasonable. As is inherent in every compromise, there will be outcomes about which a particular party was only supportive in exchange for other concessions. By commenting on the Agreement reached, Commission Staff places the parties in the position of having to justify individual items without being able to detail the steps that led to the outcome (which would not be appropriate in any event). It similarly places focus on isolated issues in the absence of the whole context of the negotiation that occurred in confidence. As a means of highlighting the difficulty this type of commentary creates, it is not possible for TGI to address in this letter Staff's statements about the information on NGV provided by TGI with reference to any additional information provided in the course of the confidential discussions.

To the extent that Staff has decided to make its views known on the present Agreement, TGI appreciates Staff having done so in a transparent manner; the alternative of having these views being conveyed in a non-transparent manner without any ability to respond would have been unpalatable. TGI nevertheless respectfully submits that the overall Settlement Agreement package should be assessed without isolating for consideration three issues where Staff might potentially have preferred a different outcome.

With that comment, Terasen Gas would like to express sincere thanks to Commission Staff and Intervenor representatives for their active participation in achieving this Negotiated Settlement Agreement on the Application. Terasen Gas also wishes to thank the NSP facilitator, Mr. Paul Cassidy, for his leadership, guidance and assistance to all parties throughout the NSP process.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Tom A. Loski

cc (e-mail only): Parties to the NSP

Appendix D

BC ENERGY EFFICIENCY ACT STANDARDS

B.C. ENERGY EFFICIENCY ACT STANDARDS:

Gas Furnaces

MEMPR ENFORCEMENT BULLETIN 09-03

What products are you regulating? The British Columbia *Energy Efficiency Act (EEA)* Automatic operating gas-fired central forced-air furnaces that use propane or natural gas and have an input rate not exceeding 66 kW (225 000 Btu/h). The regulation applies to residential and commercial furnaces.

Are you forcing me to replace my furnace? No. The regulation only applies to purchases of new or replacement furnaces. Individuals can keep their existing furnaces for as long as they wish.

What is the regulated energy efficiency standard for those products? Such products must achieve an Annual Fuel Utilization Efficiency (AFUE) equal to or greater than 90%, as tested under the standard CSA P.2-07: *Testing Method for Measuring the Annual Fuel Utilization Efficiency of Residential Gas-fired Furnaces and Boilers*. These products are commonly known as "condensing furnaces."

When will the regulations take effect in British Columbia?
For furnaces for new residential construction and all commercial buildings: January 1, 2008.
Replacement furnaces in existing dwellings: December 31, 2009.

Can I sell my inventory of non-compliant products after the effective date? For furnaces for new residential construction, any products manufactured after January 1, 2008 must comply with the regulation.

For replacement furnaces, any products manufactured after December 31, 2009 must comply with the regulation. If you have unsold inventory of products manufactured before the effective date, they can still be sold legally in British Columbia after the effective date.

Are there any exemptions to these regulations? Furnaces for recreational vehicles are exempted from the regulation. The Ministry is also providing an extended timeline for "through the wall' furnaces. A through-the-wall gas furnace is a gas-fired furnace that is designed and marketed to be installed in an opening in an exterior wall that is fitted with a weatherized sleeve. For through-the-wall gas-fired furnaces only, the 90% AFUE standard will come into effect on December 31, 2012.

B.C. ENERGY EFFICIENCY ACT STANDARDS:

Gas Furnaces

BRITISH COLUMBIA
The Best Place on Earth

MEMPR ENFORCEMENT BULLETIN 09-03

How can I tell if a product is compliant with the energy efficiency regulations? Suppliers can demonstrate compliance with the standard by ensuring that the product is listed in the Natural Resources Canada furnace database, and that the database indicates an AFUE equal to, or greater than 90%: www.oee.nrcan.gc.ca/residential/business/manu¬facturers/search/gas-furnace-search.cfm?attr=4

Who enforces this regulation? The Ministry of Energy, Mines and Petroleum Resources is responsible for enforcing all regulated standards under the *EEA*.

What are the penalties for non-compliance? Under the *EEA*, the Ministry can conduct inspections to verify compliance with the *Act* and regulations. *EEA* enforcement begins with education and voluntary compliance measures. Ministry staff follow up on all complaints and other information respecting non-compliance, and communicate directly with industry participants to develop a compliance plan.

The Ministry can also seek to have those who have contravened the legislation charged under the *Offence Act*. An offence can result in fines up to $2,000.

What do I do if I see a non-compliant product for sale or distribution? Please circulate this enforcement bulletin to the retailer or distributor. You can also report infractions to Erik Kaye, Ministry of Energy, Mines and Petroleum Resources at 250-356-1507 or Erik.Kaye@gov.bc.ca

For more information on B.C.'s *Energy Efficiency Act*:
www.empr.gov.bc.ca/EAED/EnergyEfficiency/Pages/EEAct.aspx

B.C. ENERGY EFFICIENCY ACT STANDARDS:

Gas and Propane-Fired Water Heaters

MEMPR INFORMATION BULLETIN 09-05

What products are you regulating? Storage-type water heaters with a rated storage capacity of 76 to 380 litres and an input of 75 000 Btu/h or less, for use with natural gas or propane.

Are you forcing me to replace my water heater? No. The regulation applies to voluntary purchases of new or replacement water heaters. Individuals can keep their existing water heaters for as long as they wish.

What is the regulated energy efficiency standard for those products? The Energy Factor (EF) must be greater or equal to[1] :
0.70 – (0.0005×V)

Here are the new minimum EF levels for several common sizes:

Rated Storage Capacity in litres (US gallons)	Minimum Energy Factor
114 L (30 US gal)	0.64
151 L (40 US gal)	0.62
181 L (48 US gal)	0.61
189 L (50 US gal)	0.61
246 L (65 US gal)	0.58
283 L (75 US gal)	0.56

For a lookup table with all sizes, go to:
www.empr.gov.bc.ca/EAED/EnergyEfficiency/Pages/EEAct.aspx

When will the regulation take effect? September 1, 2010

Can I sell my inventory of non-compliant products after the effective date? Any water heaters manufactured after September 1, 2010 must comply with the regulation. If you have unsold inventory of products manufactured before the effective date, they can still be sold legally in British Columbia after the effective date.

How can I tell if a product is compliant with efficiency regulations? Suppliers can ensure compliance with the standard by stocking only products that meet the minimum EF level outlined above. If the manufacturer's product literature is not clear on this point, Natural Resources Canada has a gas water heater database which lists EF by model number, which can be found at www.oee.nrcan.gc.ca/residential/business/manufacturers/search/gas-water-heaters-search.cfm?attr=4

[1] In this equation, V is the water heater's rated storage capacity in litres, as tested under the standard *CAN/CSA-P.3-04: Testing Method for Measuring Energy Consumption and Determining Efficiencies of Gas-Fired Storage Water Heaters.*

Gas and Propane-Fired Water Heaters

MEMPR INFORMATION BULLETIN 09-05

Do ENERGY STAR water heaters meet the new standard?
As of September 1, 2010, all new ENERGY STAR water heaters will be compliant with the B.C. regulation. ENERGY STAR water heaters manufactured before September 1, 2010 may not meet the standard in all cases, please check the database referenced in the previous question to confirm. Note: the ENERGY STAR standard is the same for all water heater sizes, whereas the new B.C. requirements vary with the tank size.

Who enforces this regulation? The Ministry of Energy, Mines and Petroleum Resources is responsible for enforcing all regulated standards under the *EEA*.

What are the penalties for non-compliance? Under the *EEA,* the Ministry can conduct inspections to verify compliance with the *Act* and regulations. *EEA* enforcement begins with education and voluntary compliance measures. Ministry staff follow up on all complaints and other information respecting non-compliance, and communicate directly with industry participants to develop a compliance plan.

The Ministry can also seek to have those who have contravened the legislation charged under the *Offence Act.* An offence can result in fines up to $2,000.

What do I do if I see a non-compliant product for sale or distribution?
Please circulate this information bulletin to the retailer or distributor. You can also report infractions to Erik Kaye, Ministry of Energy, Mines and Petroleum Resources at 250-356-1507 or Erik.Kaye@gov.bc.ca.

For more information on B.C.'s *Energy Efficiency Act*:
www.empr.gov.bc.ca/EEC/Strategy/EEA/Pages/default.aspx

Last Updated October, 2009

Appendix E

CONSERVATION EDUCATION AND OUTREACH EVENTS AND PARTICIPATING SCHOOLS

2010 CEO Outreach Events and 2011 Proposed Events

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
BC Association of School Business Officials	Penticton		x	50	x
BC Food Service Expo	Vancouver		x	200	x
BC Hydro Power Smart Forum	Vancouver		x	160	x
BCAMOA annual general meeting	Vancouver		x	50	x
BCAMOA semi-annual general meeting	Vancouver		x	200	x
BIA Kamloops meeting	Kamloops		x	20	x
BIA Maple Ridge regional meetings	Maple Ridge		x	80	x
BIA Victoria AGM	Victoria		x	20	x
British Columbia Recreation and Parks Association Symposium	Penticton		x	30	x
Buildex Vancouver	Vancouver		x	200	x
Canadian Federation of Apartments Association	Vancouver		x	200	x
Canadian Healthcare Engineering Society conference	Whistler		x	30	x
Kamloops Central BIA meeting	Kamloops		x	20	x
Pacific Agricultural Show	Abbotsford		x	50	x

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
Recreation Facilities Association of British Columbia Annual Conference	Oliver		x	30	x
ROMS BC AGM	Victoria		x	40	x
Strathcona BIA expo	Vancouver		x	30	x
Sustainabuild	Vancouver		x	30	x
Union of BC Municipalities Conference	Whistler		x	200	x
Abbotsford Air Show	Abbotsford	x		300	x
BC Lions Terasen Sponsored Night	Vancouver	x		600	x
BCHL Cowichan Valley	Cowichan Valley	x		250	x
BCHL Nanaimo	Nanaimo	x		200	x
BCHL Penticton	Penticton	x		300	x
BCHL Port Alberni	Port Alberni	x		300	x
BCHL Powell River	Powell River	x		400	x
BCHL Trail	Trail	x		200	x
BCHL Vernon (fall)	Vernon	x		400	x
BCHL Vernon (spring)	Vernon	x		250	x
BCHL Victoria	Victoria	x		275	x
BCSEA Kamloops Energy Fair	Kamloops	x		200	x
BerryBeat Festival	Abbotsford				x
Burnaby Lake Biodiversity Scavenger	Burnaby	x		100	x

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
Hunt					
Burnaby Multicultural Fest.	Burnaby	x		100	x
Capilano University Eco Fair	North Vancouver	x		25	x
CHBA Central Interior House and Home Residential Construction Trade Show	Kamloops	x		200	x
CHBA Central Vancouver Island Renovation Tradeshow	Nanaimo	x		300	x
CHBA Northern BC Home Show	Prince George	x		320	x
CHBA South Okanagan Spring Home Show	Penticton				x
CHBA Victoria Spring Home Show	Victoria				x
City of Richmond	Richmond				x
Collingwood Days	Vancouver	x		200	x
Coquitlam Energy Expo	Coquitlam	x		175	x
Earth Explo. School Fair	Abbotsford				x
EPIC Sustainable Living Expo	Vancouver	x		500	x
Fraser Health Authority roadshows	various	x			x

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
GVHBA Fall Home Renovation Seminar	Vancouver	x		150	x
GVHBA Summer Home Renovation Seminar	Vancouver	x		50	x
Hastings Sunrise Festival	Vancouver	x		150	x
Kelowna Spring Home Show	Kelowna	x		500	x
Kensington Community Fair	Vancouver	x		50	
Killarney Slice of Summer	Vancouver	x		75	
Latincouver Summer Festival	Vancouver				x
Lonsdale Party on the Pier	North Vancouver	x		400	x
Maple Ridge Carribean Festival	Maple Ridge				x
Moody Elementary Fair	Port Moody	x		150	x
New Westminster Hyack Festival	New Westminster				x
Newton Community Festival	Surrey	x		200	x
North Delta Lions Day	North Delta	x		150	x
Northern Health Authority roadshow					x
Ocean Park Days	White Rock	x		180	x
Organic Islands	Victoria	x		600	x

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
Sustainability Festival					
Pacific Blue Cross Eco Fair	Richmond	x		150	
Philippine Independence Day	North Vancouver	x		250	x
Play On Burnaby	Burnaby	x		200	
Play On Kelowna	Kelowna	x		400	x
Port Moody Fingerling	Port Moody	x		150	
Port Moody PAC	Port Moody	x		150	
Richmond Maritime Festival	Richmond	x		100	x
Salmon Arm Home Show	Salmon Arm	x		300	
SAP Eco Fair	Vancouver	x		130	
Sapperton Day	New Westminster	x		200	x
Spirit of the Sea	White Rock	x		400	x
SUCCESS Walk with Dragon	Vancouver	x		600	x
Surrey Canada Day	Surrey	x		400	x
Surrey Children's Festival	Surrey				x
Surrey Fusion Festival	Surrey	x		1000	x
Teddy Bear Festival	Coquitlam	x		500	x
Vancouver Canucks Superskills	Vancouver	x		450	x
Vancouver Canucks Wacky Tacky Sweater	Vancouver	x		300	

Event	Location	Residential	Commercial	Consumers Reached	Proposed 2011
(Jan 2010)					
Vancouver Canucks Ugly Sweater Night (Nov 2010)	Vancouver	x		600	x
Vancouver Giants (4 games)	Vancouver	x		1500	x
Vancouver Home and Interior Design Show	Vancouver	x		800	x
Vancouver International Bhangra Celebration	Surrey				x
Vancouver International Children's Festival	Vancouver	x		20000	x
Vancouver Island Exhibition (V.I.E.X)	Nanaimo				x
Whalley Community Festival	Surrey	x		130	x
Worksafe BC	Richmond	x		150	
Total				**38750**	

2010 Participating Schools in CEO Programs

School	Location	Program
A.R. MacNeill Secondary	Richmond	BC Green Games
A.S. Matheson Elementary	Central Okanagan District	Destination Conservation
Abbotsford Middle School	Abbotsford	BC Green Games
Anne McClymont Elementary	Central Okanagan District	Destination Conservation
Anne McClymont Elementary School	Kelowna	BC Lions presentations
Argyle Secondary	North Vancouver	Destination Conservation
Arrowview Elementary	Qualicum	BC Green Games
Aspenwood Elementary	Port Moody	BC Lions presentations
Baker Drive Elementary	Coquitlam	BC Lions presentations
Bankhead Elementary	Kelowna	BC Lions presentations
Barlow Creek Elementary	Quesnel	BC Green Games
Beaconsfield Elementary	Vancouver	Destination Conservation
Beairsto Elementary	Vernon	BC Lions presentations
Bear Creek	Surrey	BC Lions presentations
Beaver Creek Elementary	Surrey	BC Lions presentations
Begbie Elementary	Vancouver	Destination Conservation
Blewett Elementary School	Kootenay Lake	BC Green Games
Bowen Island Community School	West Vancouver	BC Green Games
Bramblewood Elementary	Coquitlam	BC Lions presentations
Brentwood College	Cowichan Valley	BC Green Games

School	Location	Program
Brooke Elementary	Delta	BC Lions presentations
Brooks Secondary	Powell River	Destination Conservation
Brooks Secondary	Powell River	BC Green Games
Buckingham Elementary	Burnaby	BC Lions presentations
Burnaby North Secondary	Burnaby	BC Green Games
Burnaby South Secondary	Burnaby	BC Green Games
C. E. Barry Intermediate	Fraser-Cascade District	Destination Conservation
Cameron Elementary	Burnaby	BC Green Games
Canyon Heights Elementary	North Vancouver	BC Lions presentations
Canyon Heights Elementary	North Vancouver	Destination Conservation
Canyon-Lister Elementary School	Lister	Wildsight
Carihi Secondary	Campbell River	BC Green Games
Carisbrooke Elementary	North Vancouver	Destination Conservation
Carisbrooke Elementary	North Vancouver	BC Green Games
Carmi Elementary	Okanagan Skaha District	Destination Conservation
Cascade Heights Elementary	Burnaby	BC Green Games
Cedar Hills	Surrey	BC Lions presentations
Cedars Christian School	Prince George	BC Lions presentations
Central Middle School	Greater Victoria	BC Green Games
Chartwell Elementary	West Vancouver	BC Green Games
Claremont Secondary School	Saanich	BC Green Games

School	Location	Program
Cleveland Elementary	North Vancouver	BC Green Games
Cliff Drive Elementary	Delta	BC Lions presentations
Columbia Elementary	Okanagan Skaha District	Destination Conservation
Colwood Elementary	Sooke District	Destination Conservation
Coquihalla Elementary	Fraser-Cascade District	Destination Conservation
Coquihalla Elementary	Fraser-Cascade District	Destination Conservation
Crystal View Elementary	Sooke District	Destination Conservation
David Cameron Elementary	Sooke District	Destination Conservation
David Thompson Secondary	Rocky Mountain	BC Green Games
DeBeck Elementary	Richmond	BC Lions presentations
Dogwood Elementary	Surrey	BC Green Games
Dorothea Walker Elementary	Central Okanagan District	Destination Conservation
Dover Bay Secondary	Nanaimo-Ladysmith	BC Green Games
Eagle View Elementary	Vancouver Island North	BC Green Games
Edgehill Elementary	Powell River	Destination Conservation
Edgehill Elementary	Powell River	BC Green Games
Edgehill Elementary School	Powell River	BC Lions presentations
Elgin Park Secondary	Surrey	BC Green Games
Ellison Elementary	Vernon	BC Green Games
Elsie Roy Elementary	Vancouver	Destination

School	Location	Program
		Conservation
Erickson Elementary School	Erickson	Wildsight
Erma Stephenson Elementary	Surrey	BC Green Games
Evans Elementary	Chilliwack	BC Lions presentations
Forest Grove Elementary	Burnaby	BC Lions presentations
Franklin Elementary	Vancouver	Destination Conservation
Fraser Heights Secondary	Surrey	BC Green Games
Fromme Elementary	North Vancouver	Destination Conservation
G T Cunningham	Vancouver	BC Lions presentations
George M Dawson Secondary	Haida Gwaii/Queen Charlotte	BC Green Games
George Pringle Elementary	Central Okanagan District	Destination Conservation
Giants Head Elementary	Okanagan Skaha District	Destination Conservation
Gibson Elementary	Delta	BC Lions presentations
Gilpin Elementary	Burnaby	BC Lions presentations
Glenmerry Elementary School	Trail	Wildsight
Glenmore Elementary	Central Okanagan District	Destination Conservation
Glenrosa Elementary	Central Okanagan District	Destination Conservation
Gordon Terrace Elementary School	Cranbrook	Wildsight
Graham Bruce	Vancouver	BC Lions presentations
Grandview	Vancouver	BC Lions presentations

School	Location	Program
Grandview Elementary	Vancouver	BC Green Games
Green Timbers	Surrey	BC Lions presentations
Grief Point Elementary	Powell River	BC Lions presentations
Grief Point Elementary	Powell River	Destination Conservation
Grief Point Elementary	Powell River	BC Green Games
H.T. Thrift	Surrey	BC Lions presentations
Haldane Elementary	Kamloops/Thompson	BC Green Games
Hampton Park	Coquitlam	BC Lions presentations
Handsworth Secondary	North Vancouver	Destination Conservation
Hans Helgesen Elementary	Sooke District	Destination Conservation
Hans Helgesen Elementary	Sooke	BC Green Games
Happy Valley Elementary	Sooke District	Destination Conservation
Harbour View Elementary	Coquitlam	BC Lions presentations
Harrison Hot Spring Elementary	Fraser-Cascade District	Destination Conservation
Heath Elementary	Delta	BC Lions presentations
Helen Gorman Elementary	Central Okanagan District	Destination Conservation
Henderson Elementary	Powell River	BC Lions presentations
Henderson Elementary	Powell River	Destination Conservation
Holly Elementary	Surrey	BC Green Games
Hope Secondary	Fraser-Cascade District	Destination Conservation

School	Location	Program
Hudson Road Elementary	Central Okanagan District	Destination Conservation
Irwin Park Elementary	West Vancouver	BC Lions presentations
Isabella Dicken Elementary School	Fernie	Wildsight
Jaffray Elementary School	Jaffray	Wildsight
James Ardiel Elementary	Surrey	BC Lions presentations
James Thompson Elementary	Powell River	Destination Conservation
John Henderson Annex	Vancouver	Destination Conservation
John MacLure Community School	Abbotsford	BC Lions presentations
John Stubbs Elementary/Middle	Sooke District	Destination Conservation
Johnston Heights Secondary	Surrey	BC Green Games
JV Humphries School	Kaslo	Wildsight
Kaleden Elementary	Okanagan Skaha District	Destination Conservation
Keith Lynn Alternative Secondary School	North Vancouver	BC Green Games
Kelly Creek Community School	Powell River	BC Lions presentations
Kelly Creek Community School	Powell River	Destination Conservation
Kelowna Secondary	Central Okanagan	BC Green Games
Kent Elementary	Fraser-Cascade District	Destination Conservation
Killarney Secondary	Vancouver	Destination Conservation
Killarney Secondary	Vancouver	BC Green Games

School	Location	Program
Klappan Independent Day School	Stikine	BC Green Games
KLO Middle School	Central Okanagan	BC Green Games
KVR Middle School	Okanagan Skaha District	Destination Conservation
Lakeview Elementary	Burnaby	BC Green Games
Langley Meadows Elementary	Langley	BC Lions presentations
Larson Elementary	North Vancouver	BC Lions presentations
Leigh Elementary	Coquitlam	BC Lions presentations
Lena Shaw	Surrey	BC Lions presentations
Lindsay Park Elementary	Rocky Mountain	BC Green Games
Lord Byng Secondary	Vancouver	Destination Conservation
Lord Roberts Elementary	Vancouver	Destination Conservation
Mamquam Elementary	Howe Sound	BC Green Games
Matsqui Elementary	Abbotsford	BC Lions presentations
McBride Elementary	Vancouver	Destination Conservation
McCloskey Elementary	Delta	BC Lions presentations
McKim Middle School	Kimberley	Wildsight
McNaughton Centre	Quesnel	BC Green Games
McNicoll Middle School	Okanagan Skaha District	Destination Conservation
Meadowbrook Elementary	Coquitlam	BC Lions presentations
Miller Park Elementary	Coquitlam	BC Lions presentations
Mission Hill Elementary	Vernon	BC Lions presentations

School	Location	Program
Montecito Elementary	Burnaby	BC Lions presentations
Morgan	Surrey	BC Lions presentations
Moscrop Secondary	Burnaby	BC Green Games
Mount Boucherie Secondary	Central Okanagan District	Destination Conservation
Nakusp Secondary	Arrow Lakes	BC Green Games
New Westminster Secondary	New Westminster	BC Green Games
Nootka Elementary	Vancouver	Destination Conservation
Norgate Community Elementary	North Vancouver	BC Lions presentations
Ocean Cliff Elementary School	Surrey	BC Green Games
Oceanview Middle School	Powell River	Destination Conservation
Old Yale Road	Surrey	BC Lions presentations
Oppenheimer	Vancouver	BC Lions presentations
Panorama Heights Elementary	Coquitlam	BC Lions presentations
Parkland Elementary	Coquitlam	BC Lions presentations
Parkland Secondary School	Saanich	BC Green Games
Parkway Elementary	Okanagan Skaha District	Destination Conservation
Peace Christian School	Chetwynd	BC Lions presentations
Penfield Elementary	Campbell River	BC Green Games
Penticton Secondary	Okanagan Skaha District	Destination Conservation
Poirier Elementary	Sooke District	Destination Conservation
Port Kells	Surrey	BC Lions presentations

School	Location	Program
Pouce Coupe Elementary	Peace River South	BC Green Games
Prince of Wales Secondary	Vancouver	BC Green Games
Queen Elizabeth Elementary	Vancouver	Destination Conservation
Ranch Park Elementary	Coquitlam	BC Lions presentations
Red Bluff Lhtako Elementary	Quesnel	BC Green Games
Reynolds Secondary	Greater Victoria	BC Green Games
Ridgeview Elementary	West Vancouver	BC Lions presentations
Ridgeway Elementary	North Vancouver	BC Lions presentations
Riverdale Elementary	Surrey	BC Green Games
Riverview Park Elementary	Coquitlam	BC Lions presentations
Robert Alexander McMath Secondary	Richmond	BC Green Games
Rochester Elementary	Coquitlam	BC Lions presentations
Rockridge Secondary	West Vancouver	BC Green Games
Rosemont Elementary School	Nelson	Wildsight
Ross Road Elementary	North Vancouver	Destination Conservation
Roy Wilcox Elementary	Coast Mountains	BC Green Games
Royal Oak Middle School	Saanich	BC Green Games
Rutland Senior Secondary	Central Okanagan District	Destination Conservation
Sangster Elementary	Sooke District	Destination Conservation
Saseenos Elementary	Sooke District	Destination Conservation
Seaview Community Elementary	Port Moody	BC Lions presentations

School	Location	Program
Shawnigan Lake	Cowichan Valley	BC Green Games
Simon Cunningham	Surrey	BC Lions presentations
Sinkutview Elementary	Nechako Lakes	BC Green Games
Sir John Franklin	Vancouver	BC Lions presentations
Sir Matthew Begbie	Vancouver	BC Lions presentations
Skaha Lake Middle School	Okanagan Skaha District	Destination Conservation
Sooke Elementary	Sooke District	Destination Conservation
Spectrum Community	Greater Victoria	BC Green Games
Springvalley Elementary	Central Okanagan District	Destination Conservation
Springvalley Elementary	Central Okanagan	BC Green Games
St Joseph's Catholic	Greater Victoria	BC Green Games
St Michaels University School - Middle	Greater Victoria	BC Green Games
St Michaels University School - Senior	Greater Victoria	BC Green Games
St. Francis Xavier Elementary	Vancouver	BC Lions presentations
Stoney Creek Elementary	Burnaby	BC Green Games
Strawberry Vale Elementary	Greater Victoria	BC Green Games
Summerland Middle School	Okanagan Skaha District	Destination Conservation
Summerland Secondary	Okanagan Skaha District	Destination Conservation
Sunshine Hills	Delta	BC Lions presentations
Taylor Park Elementary	Burnaby	BC Green Games

School	Location	Program
Timberline Secondary School	Campbell River	BC Green Games
Total Education Program	Vancouver	BC Green Games
Trout Creek Elementary	Okanagan Skaha District	Destination Conservation
Tuc-el-Nuit Elementary	Okanagan Similkameen	BC Green Games
Twin Rivers School	Castlegar	Wildsight
Unsworth Elementary	Chilliwack	BC Lions presentations
Uplands Elementary	Okanagan Skaha District	Destination Conservation
Upper Lynn Elementary	North Vancouver	Destination Conservation
Vanway Elementary	Prince George	BC Lions presentations
W D Ferris Elementary	Richmond	BC Green Games
West Bay Elementary	West Vancouver	BC Green Games
West Bench Elementary	Okanagan Skaha District	Destination Conservation
West Boundary Elementary	Boundary	BC Green Games
West Langley Elementary	Langley	BC Lions presentations
Westcot Elementary	West Vancouver	BC Green Games
Westside Academy	Prince George	BC Green Games
Westview Elementary	North Vancouver	Destination Conservation
Westwind Elementary	Richmond	BC Lions presentations
White Rock	White Rock	BC Lions presentations
William Watson	Surrey	BC Lions presentations
Willway Elementary	Sooke District	Destination Conservation

School	Location	Program
Wiltse Elementary	Okanagan Skaha District	Destination Conservation
Windebank Elementary	Mission	BC Lions presentations
Windermere Community Secondary	Vancouver	BC Green Games
Windrem Elementary	Chetwynd	BC Lions presentations
Windsor House Elementary	North Vancouver	Destination Conservation
Windsor Secondary	North Vancouver	Destination Conservation
Winlaw Elementary School	Winlaw	Wildsight

Appendix F

LETTERS OF SUPPORT

March 22, 2011

Mr. Mark Grist,
FortisBC Energy Inc.
Manager Business Development
16705 Fraser Highway
Surrey B.C. V4N 0E8

Dear Mr. Grist,

The Commercial Energy Consumers ("CEC") Association of BC is writing to you at this point in time to communicate its views with respect to the provision of FortisBC Energy Inc. ("FEI") Energy Efficiency and Conservation ("EEC") funds to support the transition of diesel oil fuelled transportation markets to natural gas fuelled transportation, particularly for the trucking component of the transportation market.

The CEC has supported the provision of FEI's EEC funds to transforming the transportation market and continues to support FEI in allocating EEC funds to this purpose for one very simple reason; it is in the interest of FEI's customers, the ratepayers. The CEC believes all ratepayers and specifically the commercial ratepayers will benefit significantly from investing in the transformation of this market. The CEC has been supportive of FEI in moving to capture this opportunity for its customers and critical whenever the movement to capture this opportunity is moving too slowly or not being planned aggressively enough.

The CEC is putting forward this position to FEI because at the stakeholder workshop, held to discuss EEC programs, we were informed of issues arising from the recent interim decision of the BC Utilities Commission ("BCUC") with respect to the Waste Management contracts and initiative being undertaken by FEI. We understand from FEI that it is interested in stakeholder's views with respect to these initiatives and that FEI might like to include these views in its submissions to the Commission relative to its planned filing with the BCUC of FEI's 2010 Report on its EEC Programs.

We understand that the Commission's recent decision may have created some uncertainty with respect to FEI providing funds to support the Waste Management initiatives and potentially with respect to advancing the transformation of the trucking transportation markets in general. The CEC would like to see this uncertainty resolved as soon as possible. The CEC would therefore support a reconsideration of the decision leading to the uncertainty or any plan to have clarification and certainty returned to the FEI transportation market transformation initiatives. We understand that FEI believes that the best opportunity to seek the required certainty would be found in BCUC regulatory process considering the issues in conjunction with the FEI 2010 EEC Report. The CEC would therefore support any initiative by FEI or the BCUC to consider the funding issues as part of the FEI 2010 EEC Report filing.

The CEC has been an active participant in the original FEI EEC application made in 2008, has been an active participant in the 2010-2011 FEI Revenue Requirements Application (“RRA”) regulatory process, including being a signatory to the Negotiated Settlement Agreement (“NSA”) arising from that process, is involved in the current BCUC regulatory process considering the approval criteria for Natural Gas for Vehicles (“NGV”) initiatives and the CEC has attended all of the EEC stakeholder workshops held since FEI instituted these consultation processes in 2009. As a consequence the CEC believes that it is reasonably informed with respect to the issues involved.

Over the course of these various regulatory proceedings the CEC has come to understand the attractiveness of the FEI NGV Programs for all customers and specifically for the CEC commercial sector. The CEC would characterize the FEI approach with respect to its NGV initiatives as having been and continuing to be nothing but open and transparent. The CEC believes that FEI has worked diligently to build understanding and support for its NGV initiatives. The CEC has directly been involved in the regulatory processes, in which the CEC believed that FEI was being provided the CEC support and consent to both pursue these NGV initiatives and to fund these initiatives from EEC funds. The CEC is precluded (as a consequence of confidentiality provisions) from discussing the specific content of discussion in a Negotiated Settlement Process (“NSP”) but may disclose its own positions at any time. The CEC believes that its sign off with respect to the RRA NSA carried the weight of its support for FEI providing funding for its NGV initiatives. Specifically the CEC believes that item 14 of the NSA supports the fuelling and transportation services to be provided and that item 11 of the NSA supports the funding envelope for the Innovative technologies for 2010-2011. The CEC in stakeholder consultation both in group processes and in numerous other consultations FEI has provided the CEC the opportunity for input, has consistently voiced the view that the NGV opportunity needs to be pursued vigorously. The CEC notes that FEI has also been cautious to ensure that it is trying to pursue these opportunities prudently and has taken the time to do so in a number of ways. The CEC believes that the current uncertainty may arise as from a perspective on a technicality with regard to FEI’s ability to provide funding for the NGV programs. The CEC believes that substance should trump technicality, although the CEC with respect supports FEI’s efforts to review the issues.

In substance, the CEC believes that the FEI NGV initiatives have a positive Total Resource Cost (“TRC”) both independently and as part of the FEI EEC programs. The CEC believes that funding from the Innovative Technologies Program (“ITP”) exceeds a TRC of 1 when including the NGV funding. The CEC understands that the NGV initiatives result in environmental reduction of greenhouse gases emissions from transportation use of fuel. Where this can be done with a positive TRC the CEC is particularly supportive and has expressed strong support for this strategic direction of FEI.

The CEC understand that whether it is dealing with BC Hydro (“BCH”) Electricity Conservation and Efficiency (“ECE”) programs or the FEI EEC programs that the fundamental principle has not been to micro-manage every program and every component of the program for basic regulatory efficiency reasons. The CEC believes that FEI has the ability to make changes, refinements or even switches of specific funding activity from the submissions it makes with respect to EEC programs at any given point in time. The CEC believes that FEI can be held accountable for the prudence of its management in after the fact review processes enabled by the BCUC regulatory processes. The CEC believes that the TRC test accountability as well as the specific program reporting accountability and the frequent stakeholder consultation opportunities the CEC is engaged in provide an ample framework for ensuring that FEI is at risk and accountable for its decisions with respect to the prudent management of the EEC funds.

The CEC believes that it has sufficient access to regulatory processes to ensure that customer perspectives are incorporated into the BCUC's final decisions with respect to the public interest. In this case the CEC believes that the FEI NGV activities are substantially in the public interest and that prolonged uncertainty with respect to funding would be counterproductive to the best interest of the ratepayers.

The CEC supports the use of EEC funds for FEI's NGV programs specifically understanding that these funds are recovered through the delivery margin from ratepayers and not directly from specific rates charged to NGV users. The CEC supports this because tf the contribution it believes this program may provide to all customers as a strategic direction for FEI and its customers.

The CEC will support whatever process FEI or the BCUC take in regard to obtaining an early resolution of the uncertainties arising from the Waste Management interim decision and specifically the FEI initiative to have these issues considered as part of its 2010 EEC Report filing. The CEC will support and participate fully in any expedited process to achieve an early resolution to the uncertainty, because the CEC believes that commercialization initiatives need the nurturing of appropriate degrees of certainty to ensure that the benefits can be developed and captured for the FEI customers and specifically those the CEC represents.

Yours truly,

David Craig
Executive Director
Commercial Energy Consumers

DWC/amp

BC Sustainable Energy Association
5 - 4217 Glanford Avenue
Victoria, BC Canada V8Z 4B9
(250) 744-2720
info@bcsea.org

21 March 2011

To:
Shawn Hill,
FortisBC
Vancouver, BC
By email: shawn.hill@fortisbc.com

Dear Shawn,

Re: FortisBC's Energy Efficiency and Conservation Plan Annual Report

This is to confirm that, as an active participant in the 2009 Energy Efficiency and Conservation Application of Terasen Gas, and a current member of FortisBC's EEC Stakeholder Group, the BC Sustainable Energy Association supports the use of FortisBC's EEC program to incent the purchase of heavy duty NGVs in place of diesel-powered vehicles where cost effective, primarily because of the greenhouse gas emissions reductions benefits. (BCSEA does not support incentives for fuel switching toward natural gas in the *passenger* vehicle sector, where hybrid and plug-in electric vehicles are on the cusp of achieving substantial market penetration.) BCSEA believes that using EEC monies in this instance is consistent with the objectives of the *Clean Energy Act* and other government policies on energy efficiency and greenhouse gas reductions.

Regards,

Thomas Hackney,
Vice-President for Policy

CITY OF VANCOUVER | 125 YEARS

OFFICE OF THE CITY MANAGER
Sustainability Group

March 22, 2011

Dave Bennett
Director Resource Planning & Market Development
FortisBC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

RE: EEC Funding of NGVs

Dear Mr. Bennett:

This letter is to confirm that The City of Vancouver has been a participant in stakeholder review sessions held by FortisBC regarding Energy Efficiency and Conservation (EEC) programs. We confirm that two stakeholder review sessions were held in 2010 (March and November) and that NGV programs were presented and discussed at these sessions. The City of Vancouver supports the continuation of the program to provide NGV incentives for heavy duty vehicle applications as adoption of NGVs in these markets provides GHG reductions and fuel cost savings to operators of NGVs.

Sincerely yours,

Sean Pander
Assistant Director, Sustainability Group
City of Vancouver

City of Vancouver, Office of the City Manager
453 West 12th Avenue
Vancouver, British Columbia V5Y 1V4 Canada
tel: 604.871.6542 *fax:* 604.673.8169
website: vancouver.ca

Cultural Capitals
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BCAOMA

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Promoting and sustaining residential housing in BC

Mark Grist
Manager, Business Development
Fortis BC Energy Inc.
16705 Fraser Hwy
Surrey, BC
V4N 0E8

Re: Letter of Support - Stakeholder Review of FortisBC EEC Programs

Dear Mr. Grist:

Further to our discussions at the EEC Stakeholder meeting held on March 15, 2010, the BC Apartment Owners & Managers Association (BCAOMA) would like to express its support for the use of Energy Efficiency & Conservation program incentives to encourage the use of Natural Gas Vehicles within BC's heavy duty transportation markets. The BCAOMA participated in stakeholder review sessions organized by FortisBC and had the opportunity to review and comment on the planned use of incentives to encourage the adoption of NGVs. During the November 24, 2010 session FortisBC provided a detailed presentation on the NGV program for BC, including the proposed use of EEC funding under the Innovative Technologies program. This presentation was favourably received by the stakeholder group. The BCAOMA believes that this consultation process meets the "Accountability Measures" defined in the Commission EEC Approval Decision G-36-09 and supports FortisBC's view that it has the necessary approvals to proceed with the NGV incentive program. The BCAOMA support this program as it has significant potential to reduce GHG emissions in the transportation sector while providing delivery rate revenues that will benefit all users of the FortisBC system.

Sincerely yours,

Marg Gordon

Marg Gordon
Chief Executive Officer
BC Apartment Owners and Managers Association

BC APARTMENT OWNERS AND MANAGERS ASSOCIATION
203–1847 WEST BROADWAY, VANCOUVER, BC V6J 1Y6
PHONE: 604.733.9440 | FAX: 604.733.9420 | TOLL FREE IN BC: 1.877.700.9440

Fraser Basin Council

March 23, 2011

Mark Grist
Manager, Business Development
Fortis BC
16705 Fraser Highway
Surrey, B.C. V4N 0E8

Dear Mark,

I am writing in followup to the meeting of Fortis BC Energy Efficiency and Conservation Stakeholder Meeting on March 15, 2011.

The Fraser Basin Council is a non-profit organization with a mandate of advancing sustainability in British Columbia, with a focus on the Fraser River watershed. We participate in the Fortis BC EEC Stakeholder sessions, as one of our strategic priorities in action on climate change and air quality.

Over the past six years, one component of FBC's climate change work has been to engage public and private sector vehicle fleets on emissions reduction activities, as a key leadership area in the transportation sector. This includes the delivery of a national green rating system – E3 Fleet – that provides third-party green certification of vehicle fleets. We have over 100 members in the program across Canada. We are technology and fuel neutral, and work with leading fleets to implement a variety of practices that reduce emissions and fuel costs.

Through our involvement in the EEC Stakeholder group over the past two years, we have been informed of Fortis BC's ongoing plans to provide incentives for natural gas vehicles (NGVs) and interest in providing natural gas compression and refueling service. We are supportive of this effort by Fortis BC to provide incentives for NGV purchase, and are also supportive of Fortis BC providing natural gas compression and refueling service. We have noticed, based on recent unsolicited calls from fleets, that there is growing interest amongst the fleets that we work with in exploring the use of natural gas as one means for reducing emissions. We also know that incentives are required to assist in overcoming the barrier of increased capital cost for NGVs. In addition, our experience in working with fleets is that in many cases there is a need for third-parties such as Fortis BC who can provide refueling services.

If you have any questions, please do not hesitate to contact me at 604-488-5359 or via email at jvanderwal@fraserbasin.bc.ca.

Sincerely ,

Jim Vanderwal
Senior Manager

1st. Floor, 470 Granville Street, Vancouver, BC, Canada V6C 1V5
Tel: (604) 488-5350 Fax: (604) 488-5351 Email: info@fraserbasin.bc.ca **www.fraserbasin.bc.ca**

Appendix G

CONTRACTOR STUDY QUALITATIVE REPORT

Terasen Contractor Telephone Interviews

Summary Of Findings

February 2011

Table Of Contents

Background And Objectives

BACKGROUND

A number of Energy Efficiency (EE) programs have been developed to encourage residential and commercial users to reduce their energy consumption. One such program is LiveSmart BC, a joint retrofit incentive initiative between FortisBC, Terasen Gas (Terasen), BC Hydro and the Ministry of Energy.

The success of these programs depends on both contractor and homeowner participation. New programs are being developed to educate and provide information to contractors and building trades. Stakeholders such as Terasen and LiveSmart BC partners are interested in understanding how to:

- Disseminate program information to those in the building industry;
- Assist or train contractors and trades to promote energy efficiency programs to homeowners; and,
- Use views and feedback from industry professionals for program development.

Methodology

METHODOLOGY

Study partners had a large number of information needs, so a qualitative phase was added to supplement the planned quantitative survey. This report summarizes findings from the qualitative in-depth interviews.

- 15 telephone interviews were conducted in December 2010 and January 2011 with contractors involved in the home building or renovation field. Contractors represented the following industries: insulation, glass, plumbing, and heating (both natural gas and electric).
- Interviewees were scheduled by a professionally trained recruiter using a screening questionnaire. Interviewees were paid a cash incentive for their involvement in this study.
- Interviews were between 30 minutes and 75 minutes in duration.
- All interviews were conducted by Anne Jacox of Cue Research.

Summary Of Findings (1)

The following observations surfaced from the qualitative phase. While they are not meant to serve as conclusive findings about all contractors, they provide a number of insights that can inform the future quantitative study.

Contractors' Involvement in Energy Efficiency (EE) Inventive Programs

- As they stand, current EE Incentive programs are not compelling enough for contractors to become fully engaged. Participants suggest that programs need to offer a greater value proposition for contractors to get involved.
- A key barrier to contractors' participation in EE Incentive programs appears to be their feeling that the rewards do not compensate sufficiently for the time and energy invested – both the added un-billable time with the customer, and extra time completing paperwork. Strategies that reduce the time required will be very important to gain contractors' full involvement. This could amount to simplified paperwork, or simplified programs that are easier for contractors to learn about and communicate to consumers
- A second key barrier to contractors' full involvement is their reluctance to promote programs that are constantly changing or may end abruptly. Several mentioned the unexpected withdrawal of federal government rebate programs that gave customers a large discount on a new furnace. Other programs offer much lower incentives and contractors fear the parameters might change without their knowledge. Because of this, contractors tend to avoid giving their input altogether, often advising customers to learn more from the program website directly. Given the importance of contractors' influence in consumers' decision making, creating more stable, enduring programs, and developing more effective methods for contractors to communicate these program offerings to consumers is recommended.

Summary Of Findings (2)

Customers' Involvement In EE Incentive Programs

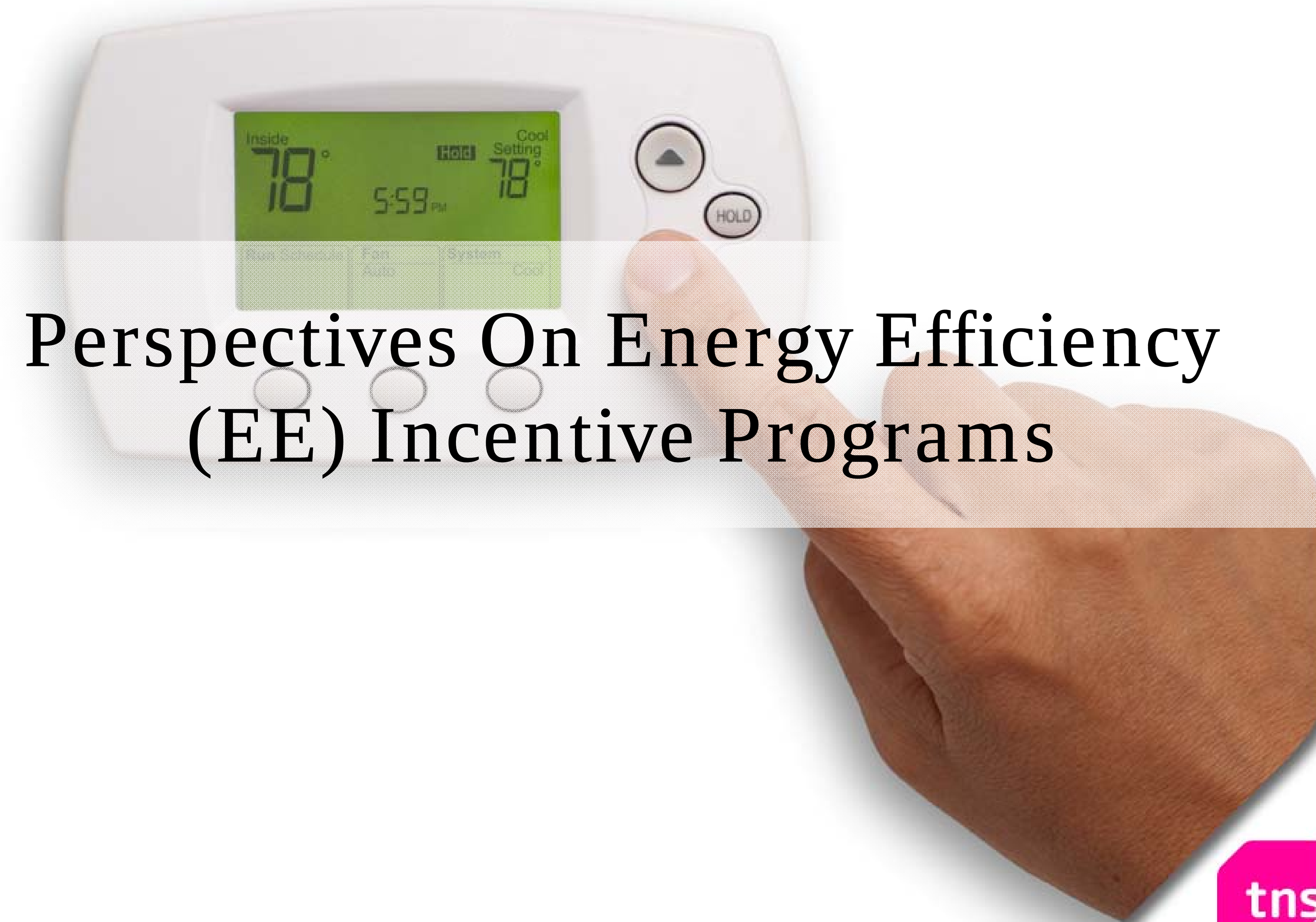
- Some contractors feel that current programs do not offer enough value to customers due to the cost of home inspection, time required for pre- and post-inspections, and paperwork required.
- They feel that EE Incentive programs *can* be of significant value to the customer, if the programs offer enough of a financial incentive.
- Contractors suggest that good EE Incentive programs should specify a deadline that motivates action. Some suggest that significant rebates toward new appliances would be the most sought-after reward for an EE Incentive program.

Communications

- To learn about EE Incentive programs, contractors recommend either emails that are specific to these programs or a forum where they could meet face-to-face and ask questions (e.g., BC Safety Authority meetings).
- The easier these programs are to communicate, the more likely they are to gain contractors' involvement in promoting them. Time (in educating customers) is money to contractors. Materials that expedite the communications process are desirable, such as brochures. Websites seem to be an expectation, and serve as an important tool for addressing consumers questions.
- Most contractors do have an advertising budget, although word of mouth is very strong in their industries.

Training And Upgrading

- While some would like opportunities to upgrade their skills, they seem opposed to training sessions that focus on marketing and sales of products or programs. Training programs that offer genuine and relevant skills would be of interest to some of the contractors.



Perspectives On Energy Efficiency (EE) Incentive Programs

Awareness Of EE Incentive Programs

Contractors

- Contractors become aware of EE incentive programs through a variety of sources:
  - Manufacturers
  - Suppliers
  - Customers
  - Other contractors
  - Brochures, newsletters
  - Their marketing consultant
- Many of the contractors involved in this study were vague about specific EE incentive programs that are available. Although they stated they are aware of EE programs, many feel they are not up to date on the availability of current offerings.

Customers

- Contractors are sometimes the source of information for the customer in creating awareness of EE incentive programs.
- Contractors sometimes offer the customer a brochure (if they have it available), but are more likely to direct the customer to the appropriate website in order to learn about the incentive program requirements themselves.

Value Of EE Incentive Programs

- While many of the interview participants feel that EE incentive programs are no longer of value, discussions indicate they can be of value if they meet one or more of the following criteria:
  - They provide enough of an incentive to motivate the customer to action, i.e., purchase a new product rather than repair an existing product.
  - The program has a specific time frame (i.e., closing date) as this further motivates the consumer to make a decision, and, they know the program will not be unexpectedly halted.
  - The incentive is of enough value (i.e., creates good business for the contractor and saves the customer money).

Barriers To Contractor Participation

- **Number of incentive programs / changes to incentive programs** – some contractors indicated that EE incentive programs are rapidly changing, hence, it is difficult to keep abreast of what is currently being offered. Many also feel that the low savings or rebate results in them being less interested in keeping current with these programs.
- **Lack of value to contractor** – many of the smaller incentive programs are not worth the contractors' efforts in filling out the required paperwork. This takes time away from the work they are getting paid for, hence, it is often not worthwhile for them.
- **Lack of value to customer** – some customers feel the incentives are too low, or are simply not interested in finding out all of the details due to the perceived low value.
- **Administrative requirements** – current incentive programs are more complicated and require more paperwork than the original ones that had larger incentives.
- **Time commitment** – due to the amount of paperwork and the need to go through the paperwork with the clients, contractors find incentive programs add time to each call, and this is time that they are not making any money on.
- **Awareness of current programs being offered** – because there are more and more incentive programs, and they keep changing, contractors are often not comfortable in being the source of information for the customer. They do not want the responsibility of ensuring the information they are providing to the customer is up-to-date, hence, they will direct the customer to a website rather than becoming involved.
- **Not relevant to their business** – many contractors feel that these programs are not relevant to their business, for example, insulation contractors generally feel that once the customer is ready for their service, they have already assessed available programs and included them in the work they request.

Perceived Barriers To Customer Participation

- **Lack of interest/value** – some incentive programs are of low value to the customer, hence, consumers are unwilling to find out all of the program information.
- **Higher cost of equipment** – programs that require new appliances, such as a high efficiency furnace, are often not desirable due to the high cost of this product, the high cost of gas, and the feeling that the furnace will cost more in repairs once the warranty expires.
- **HST** – a number of contractors indicated that sales in general have fallen as customers are reluctant to purchase a high cost appliance (e.g., high efficiency furnace) when there is question as to whether there will be a referendum on HST.
- **Additional costs** – other incentive programs have a cost associated with them to the customer, e.g., having an inspection of the home requires additional funds.
- **Confusion** – most customers are confused about the incentive program requirements and need assistance from the contractor in order to fulfill program requirements.
- **Amount of work required** – some feel there is just too much work required in order to find out about the program and gather and submit the necessary paperwork.
- **Skepticism** – some are skeptical of these programs feeling that utility costs are high and these programs are not going to reduce the high cost of their daily living. One contractor stated that consumers are increasingly complaining about the high cost of their utility bills and wondering why these companies cannot reflect incentives in the monthly cost of their bills, rather than requiring them to do additional work to get rebates.

Communications Of Energy Efficiency Programs

Preferred Means Of Communications

- Most of the contractors who participated in this study suggested that brochures that come in the mail are the preferred means of getting information to them. However, their awareness in regard to specific programs, or details of the programs, suggests that they might not read this information closely.

- Some indicate that the best means of communicating with them is in a forum where they could meet face to face, have the information explained, and have the opportunity to ask questions. One respondent stated that a representative of a utility company attending one of their industry safety meetings might be an appropriate venue. He also suggested that most contractors would show up if a free lunch was included.

- Some feel that email is the best means of communicating program information; particularly if the email is specific to incentive programs and brief enough to highlight the key information. The email might also include attachments that could be printed for distribution to customers.

- Any information that is viewed as an asset to their business (e.g., something that will aid in generating new business or making a profit) will be welcomed by contractors. Manufacturers are felt to be a valued source of information as they provide sessions to familiarize contractors with their products, provide trouble-shooting support, and offer promotions (e.g., cash back) that the contractor can use to give the customer a discount, give the customer a free product such as a thermostat, or simply use the cash to enhance their profit on the job.

Desirable Support Materials

- The following were suggested by some contractors as desirable support materials (materials they could have available for their customers) :
  - Website address; and,
  - Brochures – with pictures and bullet form information (concise, limited).
- One contractor suggested that a website to direct customers to is best, as the frequency of changes to programs is too rapid for him to become aware of, and he does not want to be responsible for providing inaccurate information to the customer.
- Some contractors indicated they would provide brochures to customers if they had them available.
- It should be noted that contractors really want the customer to assume responsibility for these incentive programs, as they do not want to add un-billable time to each project in order to educate the customers. However, they strive for customer satisfaction, hence, would like to be able to quickly give the customer information that might enhance their image as a service provider.

Contractors' Advertising

- Most have an advertising budget and the size of that budget varies considerably.
- Many use the Yellow Pages and a website to promote their business. Some will also take advantage of opportunities they are presented with, such as a deal on flyer distribution to neighbourhoods.
- Most are not really sure what the impact of their advertising is having, so will try different methodologies (that are low cost), or stick to what they have been doing.
- Word-of-mouth tends to be strong in this industry.

Co-op Advertising:

- Most contractors would be interested in any type of co-op advertising they felt would enhance their business. Brochures that are linked to utility companies (by having the utility company and contractor logo on them) are felt to be appealing as the utility endorsement would lend credibility to the contractor and provide an information piece that could be left with the customer.

Perspectives On Training And Upgrading

Training And Upgrading

- Attitudes toward training and upgrading vary substantially. Some are very interested in any training that will benefit their skills, aid in making recommendations to their customers, and keep them abreast of new technologies or techniques relevant to their field. Hands-on training is of particular value to these individuals. In other words, if the training will add value to the product they offer, and in turn, increase sales, they are interested.
- There are concerns that training offered through utility companies might be related to marketing and sales of products or programs. There is no interest in this type of training.
- Some recognize the need for on-going training and upgrading, stating that the technology is continually changing. As one interviewee stated, *"plumbers used to be able to handle any heating problems, but heating is increasingly becoming an area of specialization."* However, their time is limited as training means time in which they are not making money. Manufacturer training sessions are valued as it is specific to the products they are dealing with.
- Most indicate that they do not want these sessions to be longer than half a day (they are really looking for information sessions, rather than training sessions).
- Interest in training and upgrading varies according to:
  - The age of the contractor (e.g., how close to retirement he is, whether he is looking for new business).
  - The number of employees in the business.
  - How specialized the business is (e.g., some feel that they have such an exclusive product that new training would not benefit them).
  - The type of customer they have (e.g., if the customer has no concerns regarding the cost of a project, or if the customer has a lot of concerns about minimizing the cost of a project).

Certification

- Very few indicated they would be interested in additional certification, as this would not benefit their business or their customers.
- One interviewee indicated he would be interested in additional certification as any added credentials increase the credibility of the company to his customers, hence, an asset to business sales.

Information Needs

- Most contractors are more than satisfied with the amount of information they receive from industry association newsletters and magazines that are specifically tailored to the needs of their profession. In fact, many have difficulty keeping up with the printed materials they currently receive.
- Contractors are more likely to gain new technology information and other insights from the following sources:
  - Manufacturers;
  - Trade publications;
  - People they work with; and,
  - Other trades workers.

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Appendix H

EEC STAKEHOLDER GROUP

EEC Stakeholder Group

The Companies recognized the need for accountability in the EEC Application and proposed to form and engage an EEC Stakeholder Group. The objectives of the EEC Stakeholder Group are to guide and provide input on EEC activity. The corresponding agenda, priorities, presentations, and minutes from the March 11, 2010 and November 24, 2010 meetings are included in the Appendix.

List of EEC Stakeholder Members (as of March 15, 2011)

Member	Organization	Title
Marg Gordon	B.C. Apartment Owners and Managers Association	Chief Executive Officer
Steve Hobson	BC Hydro	Director Power Smart
Rob Noel	BC Mechanical Contractors Assoc	Commercial contractors
Mary McWilliam	BC Non Profit Housing Association	Director of Strategic Energy Management
Jim Quail	BC Public Interest Advocacy Centre	Executive Director
Erik Skehor	BC Safety Authority	Operations Manager
Tom Hackney	BC Sustainable Energy Association	Vice-President of Policy
Alison Richter	BC Utilities Commission	Regulatory Analyst - First Nations and Sustainability
MJ Whitemarsh	Canadian Home Builders' Association of BC	President
Craig Williams	Canadian Manufacturers and Exporters	Vice President
Mike Todd	Canfor Pulp	Energy Manager
Stuart Gairns	Canfor Pulp	PGI Energy Leader
Mark Hartman	City of Vancouver	Buildings Energy Programs Manager
Tony Gioventu	Condominium Home Owners' Association	Executive Director
David Craig	Consolidated Management Consultants	President
Joan Huzar	Consumers Council of Canada	
Dan Pasacreta	Crosby Property Managements, Ltd	Licensed Strata Agent
Keith Veerman	FortisBC Inc.	Manager-Energy Efficiency
Bob Purdy	Fraser Basin Council	Director, External Relations & Corporate Development
Amy Spencer-Chubey	Greater Vancouver Home Builders' Association	Director of Government Relations
Gord Monro	Heating, Refrigeration and Air Conditioning Institute of Canada	Contractor Division BC Regional
Richard Siegenthaler	Hemmera	Renewable Energy Specialist
Bruce Macgowan	IBC Technologies Inc.	President
Andrew Pape-Salmon	Ministry of Energy and Mines	Director Energy Efficiency Branch
Nir Kushnir	National Energy Equipment	General Manager, Trane
Elizabeth	Natural Resources Canada	Senior Officer, Stakeholder

Westbrook		Relations
Nina Winham	New Climate Strategies	Consultant and Rate 1 customer
Al Kemp	Rental Owners and Managers Society of BC	CEO
Cindy Stern	Tseshaht First Nation	Chief Operating Officer
Jeff Fischer	Urban Development Institute	Deputy Executive Director

EEC Stakeholder Meeting Agenda
March 11, 2010
Hyatt Hotel
655 Burrard St, Vancouver – Stanley Room

9:30 - 9:45	Registration (coffee served)
9:45 - 10:00	Welcome and Agenda
10:00 - 10:15	Roundtable Introduction
10:15 -11:15	Stakeholder Workshop: Sharing goals and priorities
11:15 – 11.30	TG topic: Alternative Energies Solutions
11:30 – 12:00	TG topic: Innovative Technologies
12.00 – 12.45	Lunch
12.45 – 14:00	2009 Annual report review and 2010 Update
14:00 -14:15	Break
14:15-15:00	Stakeholder Dialogue: Setting Action
15:00-15:15	Closing

Terasen Gas Energy Efficiency & Conservation Stakeholder Meeting
March 11, 2010

Attendees

Al Kemp, Rental Owners and Managers Society of BC
Alison Richter, British Columbia Utilities Commission, Regulatory Analyst – First Nations and Sustainability
Amy Spencer-Chubey – Greater Vancouver Home Builders' Association, Director of Government Relations
Bob Purdy, Fraser Basin Council
Bruce Macgowan - IBC Technologies
Cindy Stern – Tseshaht First Nation, CEO
Dan Pasacreta – Crosby Property Management, Licensed Strata Agent
David Craig- Consolidated Management Consultants, President
Elizabeth Westbrook-Trenholm, Natural Resources Canada, Office of Energy Efficiency, Stakeholder Relations
Erik Kaye – Ministry of Energy, Mines, and Petroleum Resources, Acting Manager, Energy Efficiency Policy
Jeff Fischer, Urban Development Institute, Deputy Executive Director
Jen Richards – City of Vancouver, Sustainability, Program Assistant
Joan Huzar, Consumers Council of Canada
Marg Gordon, BC Apartment Owners and Managers' Association
Mark Warren – FortisBC
Nina Winham, New Climate Strategies; Terasen Gas rate 1 customers
Nir Kushnir – National Energy Equipment, General Manager (Trane)
Steve Hobson – BC Hydro, Director Power Smart
Wayne Lock, BC Safety Authority, Gas Operations Manager

Regrets
Eugene Kung, BC Public Interest Advocacy Centre, Barrister & Solicitor
Mark Hartman, City of Vancouver Sustainability, Building Energy Programs Manager
Marni Vistisen, City of Prince George, Energy Manager
Rob Noel – BC Mechanical Contractors Association, Commercial Contractors
Vanessa Joehl – CHBA-BC, Built Green BC Program Administrator

Terasen Gas Staff

Beth Ringdahl	Ned Georgy
Jenny Chia	Ramsay Cook
Ken Ross	Sarah Smith
Gary Lengle	John Turner
Michelle Petrusevich	Doug Tufts
Arvind Ramakrishhnan	Mark Grist
Shawn Hill	

John Turner
Alternative Energy Solutions

(no questions)

Doug Tufts
Arvind Ramakrishhnan
Innovative Technologies

Q: Do programs have to be for upgrading?
: Solar can be for new or retrofit; hydronic, new; NGVs can be converted

Q: Why is there less money for TGVI?
a. Dollars is proportionally based on the # of customers we have on TGVI

Q: Referring to the City of Vancouver example, if I understand correctly, if solar is required in regulation, then Terasen is not going to fund it, is that the position?
a. The new buildings just have to be solar ready (ie. Piping), but don' t have to have the solar system installed
b. Utilities cannot provide incentive if it is regulated

Discussion on free riders
Q: What about municipal regulations?

a. Utilities still might advance adoption of regulation but if customer had to put one in, it would be hard to argue that utility incentive had any help with that.
b. Provincially, government is also trying to raise the bar to meet municipal regulations and not have widely diverse buildings. It's a whole market transformation and not just in isolation.
c. Terasen can comment on municipal policies and how affect programs

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Michelle Petrusevich
Structure and Overview of EEC report

(no questions)

Beth Ringdahl
Residential Programs

Scrap It Furnace – need to get stakeholder feedback on program and need to see what market is like for mid-efficient furnaces

Switch 'n' Shrink – under Fuel Switching in the report. 70% of the participants are from TGVI

Whole Home program – under joint initiatives in the report.

Hot water tank program – hard to get industry information, such as lit of eligible models from manufacturers. Terasen would like to put on directory on the website of eligible models.

Ministry policy on storage tanks have to be 80%; currently condensing storage tanks do no exist in the market today.

Q: in regulation, is BC unique?

a. First in North America; NRCan will be joining in later on. We have ambitious targets. How do we move manufacturers move this along, so need to work with utilities. We don't have the option of waiting.
b. There is a 6-12 month delay product delay from US to Canada.
c. There is a caution in mixing storage and non storage tank issues (are apples vs. oranges)

Q: What is the definition of residential customer?

a. SFDs, mobile homes, and townhomes; multi-family is considered commercial customer
b. There is multi-family homes on oil in Vancouver Island – can apply for Switch 'n' Shrink?
c. Maybe those home can apply for Efficient Boiler Program

Ramsay Cook
Commercial Programs

Q: Are there any absolute caps on funding on custom design program? How are savings measured?

a. About $3/GJ, but will not pay 100%
b. Each project will have to pass a TRC test
c. Will benchmark against energy study, then look at meter and energy consumption

Q: Will the study capture waste heat?

a. Terasen is open to study, we are just trying to get GJ savings

Q: have you looked at purchasing managers as a key audience, they are very risk adverse people and only look at costs involved?

a. Terasen can do education with purchasing managers.

Ned Georgy
Conservation for Affordable Housing

Q: In regards to ReNEW, is there continued training past 2010?

a. Looking to work with some groups on Vancouver Island.

Q: How do you choose participants for the program?

a. Partners choose because they know their audience.

Q: Who is doing the SEMP study? BC Non Profit or City Green?

a. BC Non Profit Housing Association; City Green is involved in all 3 studies. Studies have partners in sharing the cost.

Gary Lengle
Efficiency Partners Program

(no questions)

Jenny Chia
Conservation Education & Outreach

Q: Co-op on tradeshows?

a. Possibly, Terasen has to look it over.

Q: Is there a possibility of using the Pembina tool to train sales associates (ie. At big box stores)?

a. Yes

Stakeholder Action List (roundtable around the room)

Jeff at UDI – look at educating members on incentives and regulation

Al at ROMS BC – look at manufacturer home parks – they are out of the loops. Possibly have a joint Terasen and BC Hydro info session for ROMS for their board/industry

Marg at BCAMOA – provide info in newsletters to members, and include info at board meeting on Wed Mar 17.

Bob at Fraser Basin Council – get in touch with Terasen manager on NGVs

Joan at Consumers Council of Canada – likes the home (energy) labeling idea because it's a good way of letting consumers know

Amy at GVHBA – get together with Beth, Ned, and Jenny and discuss GVHBA opportunities. GVHBA also has a monthly newsletter where info can be placed.

Cindy at Tseshaht First Nation – go back to the community, communicate about Terasen programs for people that are not in social housing; will be speaking about Terasen at national Aboriginal Housing Forum in Calgary

Wayne at BC Safety Authority – is concerned about contractors not having the skill set to install the new technology/equipment; have to look at training and if need to upgrade training, perhaps suppliers should provide training for installers

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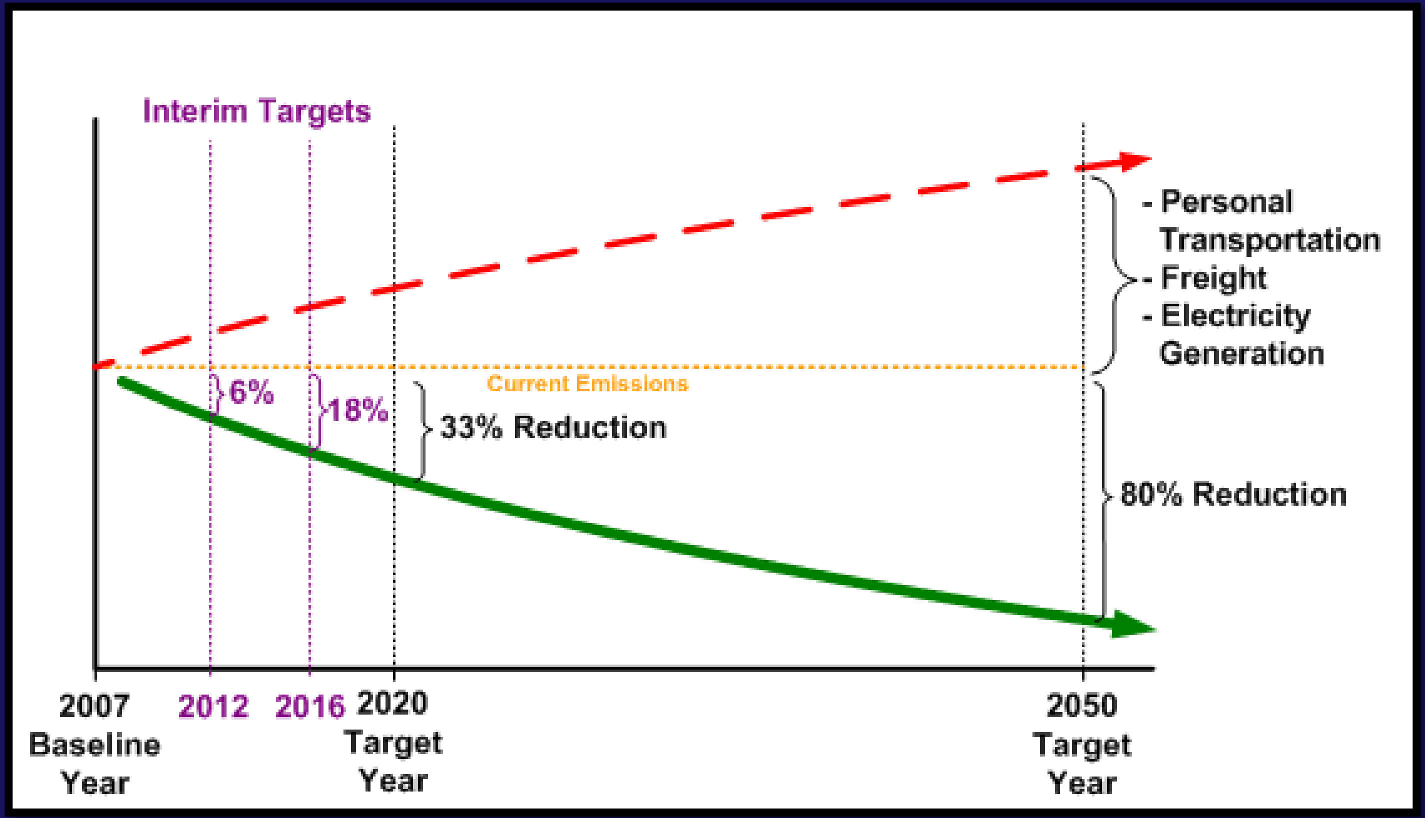
Terasen Gas

Alternative Energy Solutions

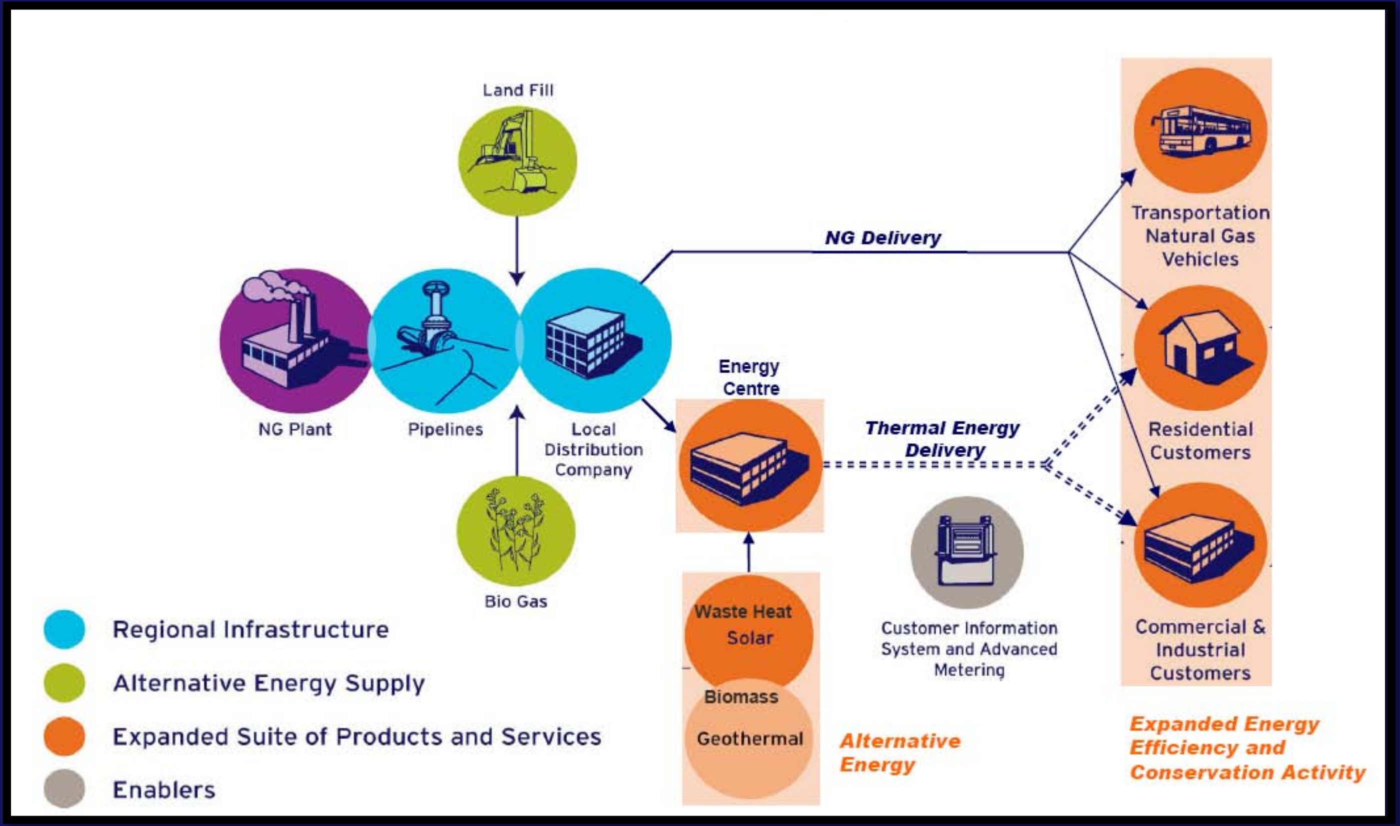
John Turner, Director, Energy Solutions

British Columbia Legislated Targets

- **Reducing BC's GHG emissions by at least 33% below 2007 levels by 2020 and at least 80% below by 2050**



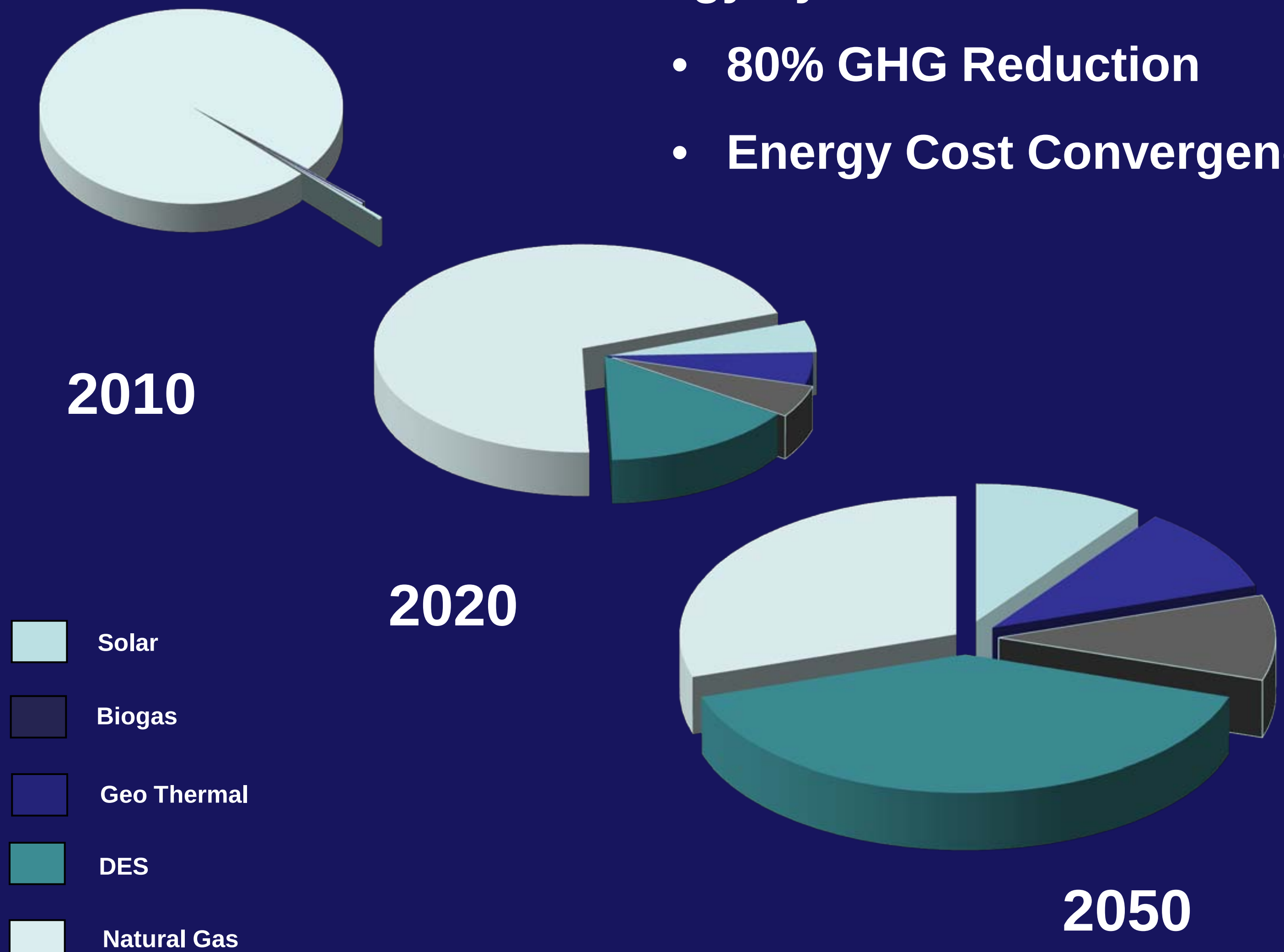
Terasen Approach



A Carbon Lean and Energy Diverse Future

Energy System Evolution

- **80% GHG Reduction**
- **Energy Cost Convergence**



Terasen Large Scale Alternative Energy System Examples

District Energy for Brownfield Re-development

- **Location:** Coquitlam, BC
- **Type of Development:**
    - 89 acre brownfield re-development
        - **3,700** residential units,
        - 275,000 sq. ft of commercial/retail
        - 600,000 sq. ft. of business park/ light industrial
        - 16 acres of open space, parks and trails.
- **Energy System:**
    - District Energy System to incorporate alternative energy sources integrated with natural gas:
        - Local waste heat (industrial recycling plant)
        - Geothermal from groundwater or earth
        - Possibilities for biomass

Fraser Mills Site Plan

- **Environmental Benefits**
    - *Possibilities for biomass*
    - *Reduced demand on BC's electricity grid*
    - *Savings of >8,200 tonnes of GHGs per year (equivalent to removing >2,500 cars from the road)*

Terasen Large Scale Alternative Energy System Examples

Individual Geothermal Systems for Residential Development

Aquattro Site

- **Location:** Colwood, BC
- **Type of Development:**
  - 563 unit residential development
  - 24 buildings

Geothermal drilling

- **Energy System:**
  - *Individual geothermal systems*
    - Ground heat extraction integrated with natural gas
    - Progressive installation as community develops
- **Environmental Benefits**
  - *Reduced demand on BC's electricity grid*
  - *Savings of 2 tonnes of GHGs a year for each 2,000 square foot residential unit*

Terasen Large Scale Alternative Energy System Examples

Expandable Energy System for Urban Infill

- **Location:** Victoria, BC
- **Type of Development:**
  - New & existing buildings
    - 631 new residential units,
    - 175,000 sq. ft of new commercial/retail
    - Multiple existing buildings adjacent to new development.
- **Energy System:**
  - Geothermal system for first two new buildings integrated with natural gas
  - Capability to expand to complete District Energy System incorporating waste heat from ice rink for both new & existing buildings.

Hudson Building

- **Environmental Benefits**
  - *Reduced demand on BC's electricity grid*
  - *Energy Usage in new buildings is reduced by up to 59% & GHGs by up to 73%*

The Intersect between EEC & AES

- Programs will be designed to reduce amount capitalized and charged back to customer
- Programs will be agnostic as to source for energy savings, but cannot be electric baseboard
- Programs will be agnostic as to AES proponents – don't have to work with Terasen to obtain EEC funds for AES projects

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Terasen Gas

Energy Efficiency and Conservation Innovative Technologies

Doug Tufts
Arvind Ramakrishhan

Innovative Technologies

Background

- TGI and TGVI Energy Efficiency and Conservation Application
  - requested $3 million for Innovative Technology Programs
  - filed on May 28, 2008
- TGI 2010 and 2011 Revenue Requirement Application
  - requested $7.003 million
  - filed on June 15, 2009
- TGVI 2010 and 2011 Revenue Requirement Application
  - requested $1.434 million
  - filed June 29, 2009
- TGI and TGVI Received a Negotiated Settlement on November 13, 2009
  - funding for Innovative Technologies approved

Innovative Technologies

Approved Funding
for Innovative Technologies ($000)

	2010	2011	Total
TGI	2,334	4,669	**7,003**
TGVI	0,478	0,956	**1,434**
Total	**2,812**	**5,625**	**8,437**

Innovative Technologies

Terms of the Negotiated Settlement TGI & TGVI

- That Innovative Technologies be managed as a separate portfolio from our other EEC Programs
- That Innovative Technologies portfolio have a Total Resource Cost (TRC) weighted average of 1.0 or greater
- That Terasen will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee

Innovative Technologies

Proposed Program Costs, TGI

TGI	2010	2011	Total
Solar Thermal	288,000	576,000	**$864,000**
Commercial NGV	808,000	1,616,000	**$2,424,000**
Hydronic Heating Systems	120,000	280,000	**$400,000**
Residential GSHP Systems	107,000	213,000	**$320,000**
Alternative Energy Systems	605,500	1,210,500	**$1,816,000**
Total	**$1,928,500**	**$3,895,500**	**$5,824,000**

Innovative Technologies

Proposed Program Costs, TGVI

TGVI	2010	2011	Total
Solar Thermal	60,000	120,000	**$180,000**
Commercial NGV	160,000	340,000	**$500,000**
Hydronic Heating Systems	25,000	50,000	**$75,000**
Residential GSHP Systems	22,500	44,500	**$67,000**
Alternative Energy Systems	126,000	254,000	**$380,000**
Total	**$393,500**	**$808,500**	**$1,202,000**

Innovative Technologies

Natural gas reductions for TGI and TGVI for the measured life of the programs.

- **A reduction of 577,000Gj**
- **A reduction of 505,000 tonnes of C02**

	Gigajoules	**Alternative energy savings (Diesel liters)**	**Tonnes of C02**
Hydronic heating Systems	24,000		1,325
Alternative energy systems	369,000		20,295
Commercial NGV	-896,000	22,689,000	473,361 (net C02)
GSHP systems	47,514		2,613
Solar thermal hot water	137,154		7,543

California Standard Protocol Tests

Cost Test	Key Question Answered	Approach
TRC	Is the overall economy better off with DSM?	All costs & benefits regardless of who accrues them
SCT	Is the society, Nation better off as a whole?	Includes non energy benefits
PCT	Will the participant benefit over the measure life?	costs & benefits to the program participant
UCT	Will Utility bills rise over time?	costs & benefits that accrue to the Utility system
RIM	Will Utility rates increase over time?	Takes lost revenue as cost & attempts to measure rate impact to all customers.

Proposal for Innovative Technologies

- Conventional EEC Programs
- Innovative Technologies Portfolio
  - Partner Contributions netted out of incremental cost

Example with Solar Thermal – City of Vancouver

Total incremental cost-$5,700(Solar ready bylaw)

- Partner Incentive-$3,375
- Utility Incentive proposed-$1000
- Participant cost-$1,325

System cost into the model = $2,325

Proposed Innovative Technologies

TGI

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.8	0.8	288,000	576,000	$864,000
Commercial NGV	1.5	1.5	808,000	1,616,000	$2,424,000
Hydronic Heating Systems	0.4	0.4	120,000	280,000	$400,000
Residential GSHP Systems	0.2	0.2	107,000	213,000	$320,000
Alternative Energy Systems	1.0	1.1	605,500	1,210,500	$1,816,000
Portfolio level-TGI	1.2	1.2	$1,928,500	$3,895,500	$5,824,000

Proposed Innovative Technologies

TGVI

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.8	0.8	60,000	120,000	$180,000
Commercial NGV	1.4	1.4	160,000	340,000	$500,000
Hydronic Heating Systems	0.4	0.3	25,000	50,000	$75,000
Residential GSHP Systems	0.2	0.2	22,500	44,500	$67,000
Alternative Energy Systems	1.1	1.1	126,000	254,000	$380,000
Portfolio level-TGVI	1.2	1.2	$393,500	$808,500	$1,202,000

Proposed Innovative Technologies

Portfolio Level summary (TGI , TGVI)

company	Portfolio level TRC	Program Costs($)		
		2010	2011	Total
TGI	1.2	1,928,500	3,895,500	5,824,000
TGVI	1.2	393,500	808,500	1,202,000
Total		2,322,000	4,704,000	7,026,000

Innovative Technologies - Summary

Application of the Weighted Average TRC

- Program portfolio of activities

- Remove the partner incentive costs from the total incremental cost

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Terasen Gas

Structure & Overview of EEC Report

Presented by **Michelle Petrusevich**, MA
DSM Program Development Lead

EEC Report – Why?

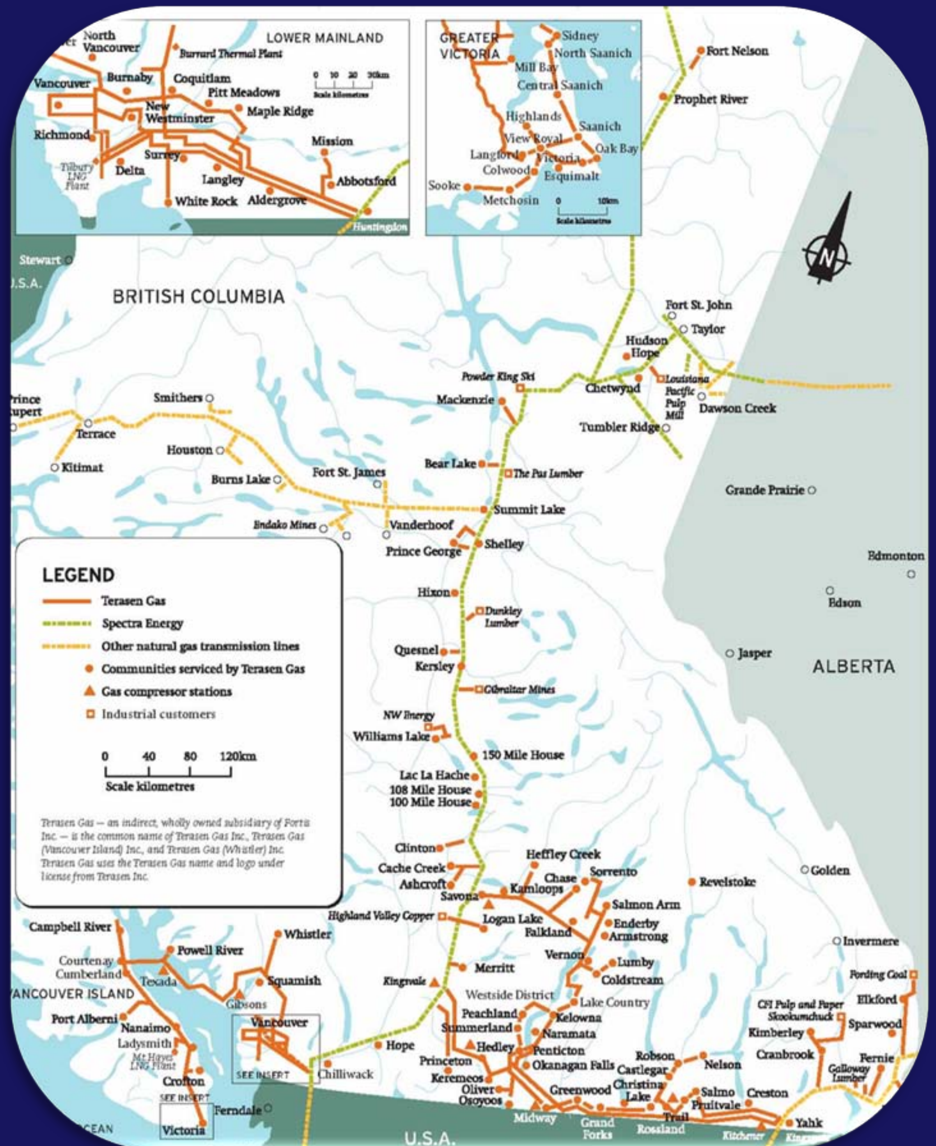
- May 2008 - EEC Application submitted
- April 2009 - BCUC approved the EEC Application

"A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI."

2009 EEC Report Structure

- Introduction & Background
- 2009 Program Results (by program area)
- 2010 Programs
- Data Gathering, Reporting & Internal Audit
- Attribution Section
- Conclusion
- Appendices

Background: DSM Programs on TGI & TGVI



2009 Program Results* - Highlights

Please refer to the Annual Report – to be filed with the BC Utilities Commission by March 31, 2010

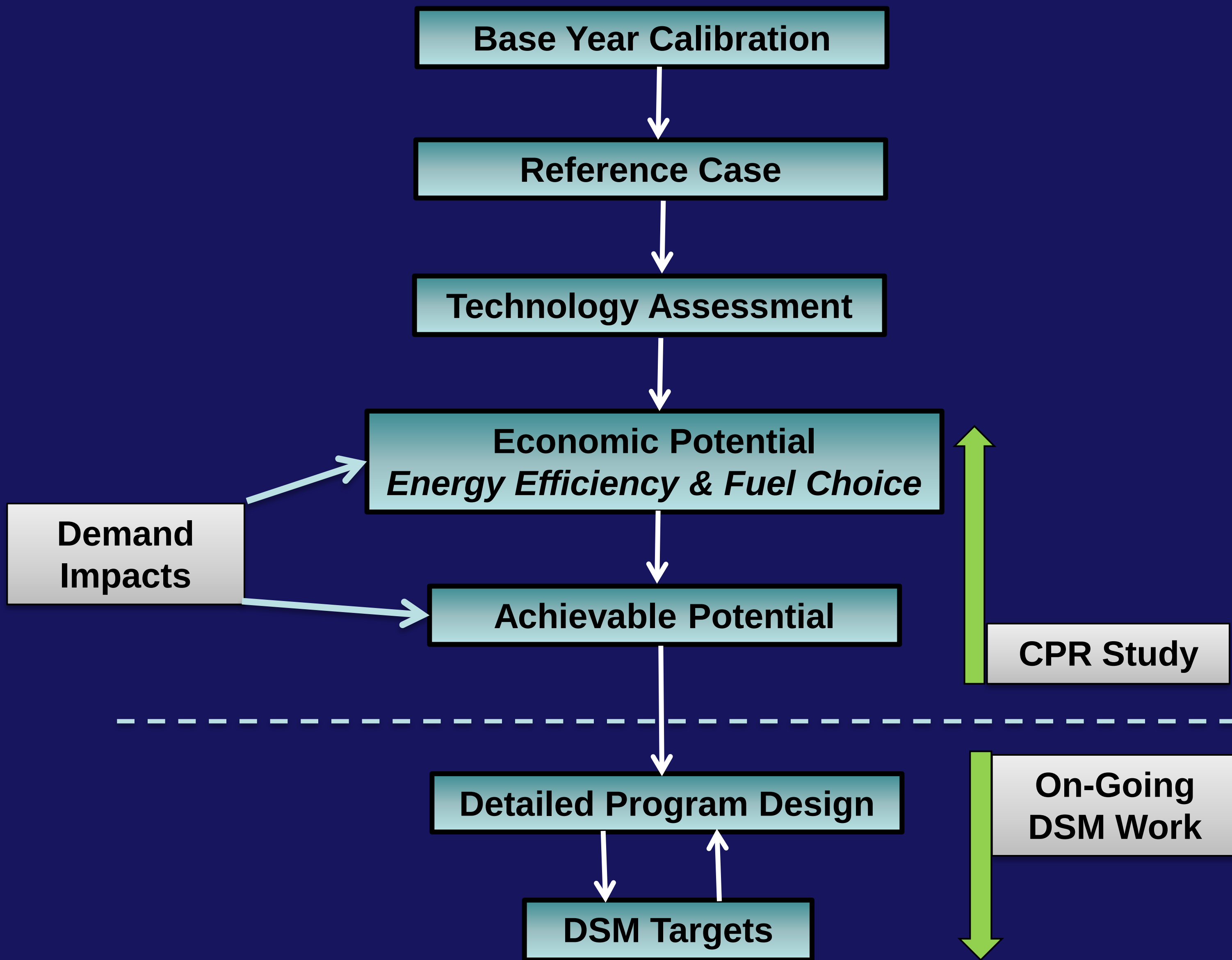
2010 Planned Program Results - Highlights

Please refer to the Annual Report – to be filed with the BC Utilities Commission by March 31, 2010

Research & Evaluation Activities

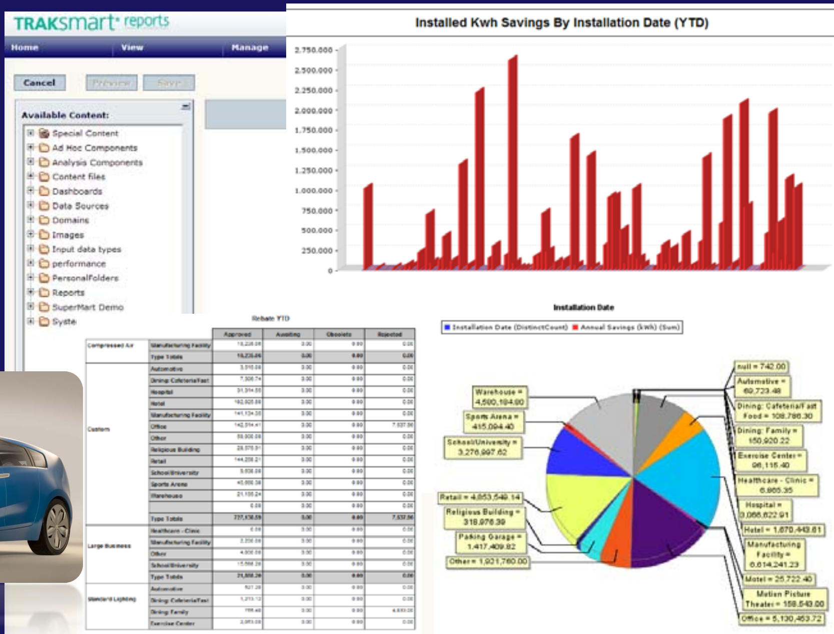
- 2009 Research & Evaluation Activities
  - REUS Study
  - Sustainability and Social Responsibility Attitudes Study Report
  - Residential Retrofit Market Evaluation for Terasen Gas
  - Energy Star Heating System Upgrade Evaluation (Phase 2 – Billing Analysis)
- 2010 Research & Evaluation Activities
  - Efficient Boiler Program Evaluation
  - Okanagan Spray Saver Pilot Program
  - Commercial Energy Assessment
  - Tankless Water Heater Pilot
  - Home Labelling Pilot in Prince George

Conservation Potential Review (CPR)



Processes and Controls Overview

- Description of current control mechanisms for data gathering, reporting and internal control processes
- DSM Tracking (TrakSmart) System
- Internal Audit



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2010 Residential Programs

Beth Ringdahl,

Residential Program Manager

Presentation Agenda

- Achievements since last meeting
  - NRCan MOU
  - Streamlining Internal Processes
  - Outsourced administration
- 2009 Program Results
- 2010 Program Plan

2009 Residential Program Results

Program Name	Total Incentive & Non Incentive Expenditures ($ 000's)	Participants #' s	TRC
Energy Star Heating System Upgrade (Terasen + LiveSmartBC)	2,104	7930	1.3
EnerChoice Fireplace	84	794	2.5
EcoEnergy Home Energy Assessments – LiveSmart BC	408	5445	"0"

Residential TRC:	**1.3**

*Note: the numbers are preliminary and could be modified for the final report

2010 Residential Programs

- Switch 'N' Shrink
  - Oil and Propane Conversions
- Space Heating
  - EnerChoice Fireplace
  - Furnace Scrap it - TBD
- Domestic Hot Water
  - ENERGYSTAR Tanks
  - Tier 3 Pilots
  - Appliances
- Whole home
  - Utility Partnership + LiveSmartBC
    - Building Envelope Incentives
    - EnerGuide 80

Switch 'N' Shrink

Conversion from High to Low Carbon Fuels

$1000 Rebate

- Launched Jan 1
- Saving $ and environment
- Partnering with associations
- $50 rebate for Variable Speed Motor (BC Hydro, FortisBC)
- Goal: 750 participants

Oil and Propane savings

Domestic Hot Water

ENERGYSTAR ® Tanks

$100 Rebate -
$50 consumer +
$50 contractor

2 GJ per year + early retirement

- Launching May
- Supports Sept 1 regulations
- 90% emergency replacement
- Goal: 3000 retrofit participants
- New construction - TBD

ENERGY STAR

Domestic Hot Water

New Technologies and Conservation

- Tier 3 Technologies – 80% +
  - Condensing Water Tank pilot
  - Tankless H20 Heater pilot
- Appliances - Front load washers
- Hot Water Conservation Campaign

Save
hot water =
save GJs

Whole Home Partnerships

- Utility Partnership
- One stop rebate shop
- Efficiencies through shared marketing, administration and DSM expertise
- Marketing Launch: Fall weatherization campaign
- Leverage any other funds available

Terasen Gas

BC hydro powersmart

FORTISBC powersense

BRITISH COLUMBIA
Ministry of Energy, Mines and Petroleum Resources

ecoENERGY
an ecoACTION initiative

2010 Timeline

Project	Q 1	Q 2	Q 3	Q 4
Switch 'N' Shrink				
BC Utility Partners / LiveSmart				
Energy Star Water Tank				
EnerChoice				
Tier 3 Water Heater Pilots				
Furnace Scrap It – TBD				
EnerGuide 80 Pilot - TBD				

Burn blue. Save green.

Terasen Gas

Commercial Programs

Ramsay Cook

EEC Program Manager, Commercial

2009 Programs Results

Program Name	Total Incentive & Non Incentive Expenditures (000 $)	Participants	TRC
Light Commercial Energy Star Boiler Program	52	11	3.4
Efficient Boiler Program	943	65	2.0
Energy Assessment Program	77	49	2.3
Okanagan Spray n' Save	28	276	2.8

Commercial TRC:	**2.2**

*Note: the numbers are preliminary and could be modified for the final report

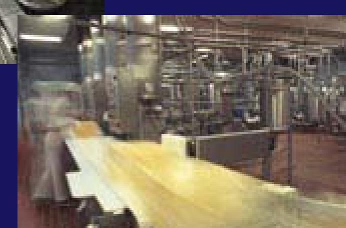
2010 Programs Summary

Hot Water

Custom Design

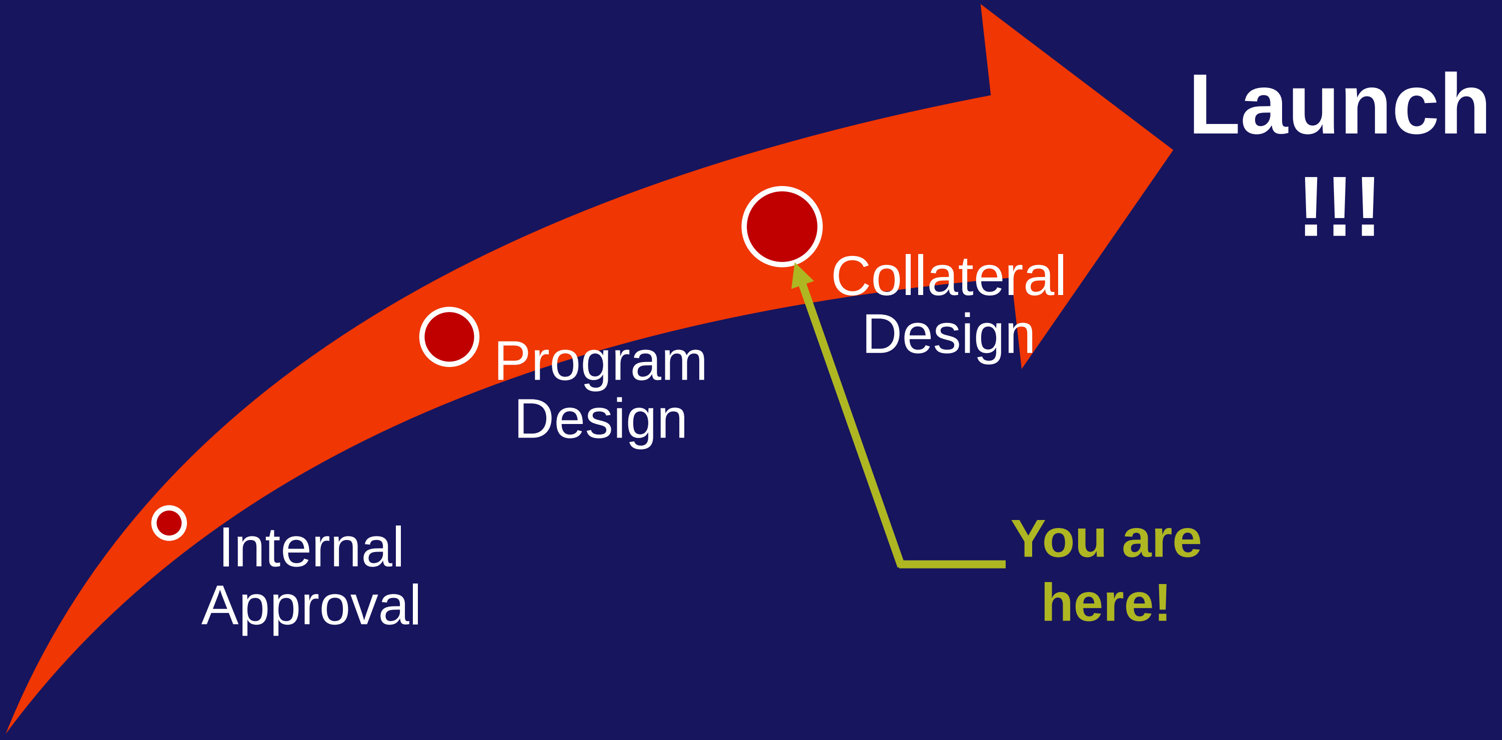
Commissioning

Commercial Cooking

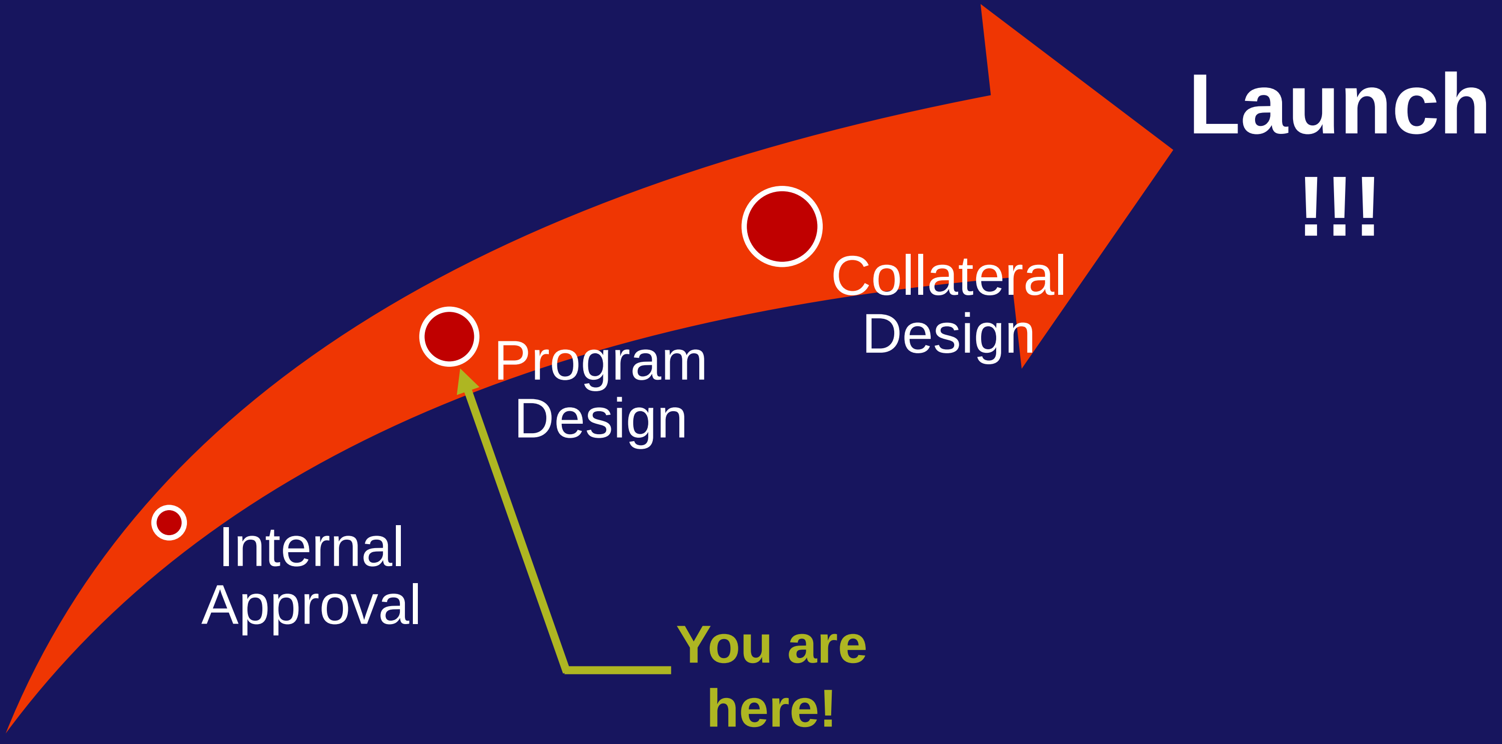


Process Heat

Efficient Water Heaters Program



Custom Design Program



Commissioning Program

Terasen /
BC Hydro
M.O.U

- Initial discussions
- Intention to collaborate

BC Hydro
C. Op
Program

- Background Research
- Savings / Cost data

Terasen Gas

Internal Approval

Onward!

Commercial Cooking Program

Initial Research → Spoken with potential participants → More work to be done!

Process Heat Program

CPR = Manufacturing Sector Conservation Potential Review

Consultant Study

CPR Update

Promising Measures

Full Program Design

Timeline for 2010

Project	Q 1	Q 2	Q 3	Q 4
Efficient Water Heaters Program				
Custom Design Program				
Commissioning Program				
Commercial Kitchen				
Process Heat Program				

Other New Initiatives

Radiant Tube
Heaters Pilot Study

Victoria Pre-Rinse
Spray Valves

Efficient Boiler
Program Revisions

Energy Assessment
Program Revisions

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Terasen Gas

Conservation for Affordable Housing

Ned Georgy

Program Manager

2009 Programs Preliminary Results

Project Name	Total Incentive & Non Incentive Expenditures ($ 000's)	Participants / Units	TRC
Meridian Village (EEC)	230	124	1.0
LiveSmart Carry Over (MEMPR)	992	557	1.1
Energy Conservation for Affordable Housing Forum	8	83	N/A

Total Program Area TRC:	**1.0**

*Note: the numbers are preliminary and could be modified for the final report

2010 Programs Summary

- REnEW
- Energy Savings Kits
- Energy Conservation Assistance Program
- 3 Studies
- Energy Conservation for Affordable Housing Forum

2010 Programs Summary

REnEW

Residential Energy Efficiency Works

2010 Programs & Partnerships

Energy Savings Kits
(EEC and MEMPR)

Energy Conservation Assistance Program
(EEC and MEMPR)

Studies

- Affordable Energy Conservation Strategy paper
- Strategic Energy Management Plan
- Co-operative Housing Federation (CHF) Energy Performance Inventory

2010 Timeline

Project	Q 1	Q 2	Q 3	Q 4
REnEW				
Energy Saving Kit				
Energy Conservation Assistance Program				
3 Studies				
Energy Conservation for Affordable Housing Forum				

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2010 Efficiency Partners Programs

Gary Lengle,
Efficiency Partners
Program Manager

Efficiency Partners Program

- Supply Chain
  - Manufacturers
  - Suppliers
  - Distributers
- Direct Retail
  - Big Box Stores
- Service Providers
  - B-ticket Gas Fitters
  - ECO Energy Home Auditors
  - C-ticket Maintenance Groups
- Codes and Standards
  - BCSA
  - MEMPR
  - Industry Stakeholders

2009 Programs Results

Program Name Efficiency Partners Program	Total 2009 Consolidated Expenditures ($ 000's)
Contractor Program	11
Co-op Advertising	14
Codes and Standards	13

*Note: the numbers are preliminary and could be modified for the final report

Efficiency Partners 2009 Program Activities

- TGVI Contractor Focus Groups
- Identifying Partner groups
- Codes and Standards review
- Identifying other utility Enabling programs

Efficiency Partners 2010 Program Activities

- Contractor Focus groups TGI service area
- New Contractor Program Development
- Contractor Quarterly Newsletter
- Contractor Workshops
- Building Code Development
- ECO Energy Audit process review

2010 Timeline

Efficiency Partners Project	Q 1	Q 2	Q 3	Q 4
Codes and Standards				
New Contractor Program				
Review of ECO Energy Audit				
Contractor Quarterly Newsletter				
Contractor Work Shops				
Additional Partner Groups				
Building Code Development				

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Conservation Education & Outreach

Jenny Chia

Program Manager

2009 Results

Program Name	Total (Non Incentive) Expenditures ($ 000's)	Participants
Print and Online Publications	**219**	n/a
Trade Shows and Events	**102**	Approx. 4900
Schools Programs	**117**	Approx. 230+ schools
Energy Champion Program	**127**	Ongoing into 2010
Team Terasen Outreach	**47**	Approx. 35,000

*Note: the numbers are preliminary and could be modified for the final report

New Initiatives

- Ethnic Outreach
- Commercial Outreach
  - Trade shows
  - BIA regional meetings
- Energy Champion
  - Vancouver Canucks
- Behaviour Change Pilots:
  - Vancouver Coastal Health Authority
  - Okanagan Municipalities
- Terasen employees outreach

2010 Timeline

Project	Q 1	Q 2	Q 3	Q 4
Print and Online (ongoing)				
Ethnic Outreach				
Trade Shows and Events				
School Programs				
Energy Champion				
Team Terasen				
Behaviour Change Pilots				
Terasen Employees outreach				

Energy Efficiency and Conservation Innovative Technologies

Doug Tufts and Arvind Ramakrishhnan

Innovative Technologies

Background

- TGI and TGVI Energy Efficiency and Conservation Application
  - requested $3 million for Innovative Technology Programs
  - filed on May 28, 2008
- TGI 2010 and 2011 Revenue Requirement Application
  - requested $7.003 million
  - filed on June 15, 2009
- TGVI 2010 and 2011 Revenue Requirement Application
  - requested $1.434 million
  - filed June 29, 2009
- TGI and TGVI Received a Negotiated Settlement on November 13, 2009
  - funding for Innovative Technologies approved

Innovative Technologies

Approved Funding
for Innovative Technologies ($000)

	2010	2011	Total
TGI	2,334	4,669	**7,003**
TGVI	0,478	0,956	**1,434**
Total	**2,812**	**5,625**	**8,437**

Innovative Technologies

Terms of the Negotiated Settlement TGI & TGVI

- That Innovative Technologies be managed as a separate portfolio from our other EEC Programs
- That Innovative Technologies portfolio have a Total Resource Cost (TRC) weighted average of 1.0 or greater
- That Terasen will consult with stakeholders on the practical application of the weighted average TRC through the EEC Advisory Committee

Innovative Technologies

Proposed Program Costs, TGI

TGI	2010	2011	Total
Solar Thermal	288,000	576,000	**$864,000**
Commercial NGV	808,000	1,616,000	**$2,424,000**
Hydronic Heating Systems	120,000	280,000	**$400,000**
Residential GSHP Systems	107,000	213,000	**$320,000**
Alternative Energy Systems	605,500	1,210,500	**$1,816,000**
Total	**$1,928,500**	**$3,895,500**	**$5,824,000**

Proposed Program Costs, TGVI

TGVI	2010	2011	Total
Solar Thermal	60,000	120,000	**$180,000**
Commercial NGV	160,000	340,000	**$500,000**
Hydronic Heating Systems	25,000	50,000	**$75,000**
Residential GSHP Systems	22,500	44,500	**$67,000**
Alternative Energy Systems	126,000	254,000	**$380,000**
Total	**$393,500**	**$808,500**	**$1,202,000**

Innovative Technologies

Terasen Gas

Natural gas reductions for TGI and TGVI for the measured life of the programs.

	Gigajoules	Alternative energy savings (Diesel liters)	Tonnes of C02
Hydronic heating Systems	24,000		1,325
Alternative energy systems	369,000		20,295
Commercial NGV	-896,000	22,689,000	473,361 (net C02)
GSHP systems	47,514		2,613
Solar thermal hot water	137,154		7,543

- **A reduction of 577,000Gj**
- **A reduction of 505,000 tonnes of C02**

California Standard Protocol Tests

Cost Test	Key Question Answered	Approach
TRC	Is the overall economy better off with DSM?	All costs & benefits regardless of who accrues them
SCT	Is the society, Nation better off as a whole?	Includes non energy benefits
PCT	Will the participant benefit over the measure life?	costs & benefits to the program participant
UCT	Will Utility bills rise over time?	costs & benefits that accrue to the Utility system
RIM	Will Utility rates increase over time?	Takes lost revenue as cost & attempts to measure rate impact to all customers.

Proposal for Innovative Technologies

- Conventional EEC Programs

- Innovative Technologies Portfolio
  - Partner Contributions netted out of incremental cost

Example with Solar Thermal-City of Vancouver

Total incremental cost-$5,700(Solar ready by law)

- Partner Incentive-$3,375
- Utility Incentive proposed-$1000
- Participant cost-$1,325

System cost into the model=$2,325

Proposed Innovative Technologies

TGI

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.8	0.8	288,000	576,000	$864,000
Commercial NGV	1.5	1.5	808,000	1,616,000	$2,424,000
Hydronic Heating Systems	0.4	0.4	120,000	280,000	$400,000
Residential GSHP Systems	0.2	0.2	107,000	213,000	$320,000
Alternative Energy Systems	1.0	1.1	605,500	1,210,500	$1,816,000
Portfolio level-TGI	1.2	1.2	$1,928,500	$3,895,500	$5,824,000

Proposed Innovative Technologies

TGVI

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.8	0.8	60,000	120,000	$180,000
Commercial NGV	1.4	1.4	160,000	340,000	$500,000
Hydronic Heating Systems	0.4	0.3	25,000	50,000	$75,000
Residential GSHP Systems	0.2	0.2	22,500	44,500	$67,000
Alternative Energy Systems	1.1	1.1	126,000	254,000	$380,000
Portfolio level-TGVI	1.2	1.2	$393,500	$808,500	$1,202,000

Proposed Innovative Technologies

Portfolio Level summary(TGI , TGVI)

company	Portfolio level TRC	Program Costs($)		
		2010	2011	Total
TGI	1.2	1,928,500	3,895,500	5,824,000
TGVI	1.2	393,500	808,500	1,202,000
Total		2,322,000	4,704,000	7,026,000

Innovative Technologies -Summary

Application of the Weighted Average TRC

- Program portfolio of activities

- Remove the partner incentive costs from the total incremental cost d5

Back up Slides

Slide 15

d5 Arvind could you add some content in the notes addressing why we are removing the partner form the TRC model?
dtufts, 3/4/2010

Innovative Technologies –TGVI Break up

2010					Ratios		
		per participant			PCT	RIM	TRC
Innovative Technologies	participants	Incentive ($)	Admin($)	Total($)			
Hydronic Heating Systems	21	1000	200	24,939	1.1	0.4	0.4
Alternative Energy Projects	1	120,000	2,000	126,774	2.1	0.7	1.1
NGV Vehicles	3	50,000	500	167,923	1.3	1.0	1.4
Residential Ground Source Heat P	7	3000	200	22,168	0.4	0.5	0.2
Solar Thermal Hot Water	50	1000	200	59,854	2.1	0.6	0.8
Total				401,659	2.0	0.1	1.2
BCUC Approved amount				478,000			
Available funds				76,341			

2011					Ratios		
		per participant			PCT	RIM	TRC
Innovative Technologies	participants	Incentive ($)	Admin($)	Total($)			
Hydronic Heating Systems	42	1000	200	49,878	0.8	0.3	0.3
Alternative Energy Projects	2	120,000	2000	253,548	1.5	0.9	1.1
NGV Vehicles	7	50000	500	335,847	1.8	0.7	1.4
Residential Ground Source Heat P	14	3000	200	44,336	0.3	0.7	0.2
Solar Thermal Hot Water	100	1000	200	119,708	1.5	0.7	0.8
Total				803,317	2.1	0.1	1.2
BCUC Approved amount				956,000			
Available funds				152,683			

Innovative Technologies –TGI Break up

terasen Gas

2010					Ratios		
		per participant			PCT	RIM	TRC
Innovative Technologies	**participants**	Incentive ($)	Admin($)	Total($)			
Hydronic Heating Systems	**100**	1000	200	120,000	0.8	0.4	0.4
Alternative Energy systems	**3**	230,000	2,000	605,217	2.4	0.7	1.0
NGV Vehicles	**16**	50,000	500	808,000	1.8	0.7	1.5
Residential Ground Source Heat pumps	**33**	3000	200	106,667	0.3	0.7	0.2
Solar Thermal Hot Water	**240**	1000	200	288,000	1.5	0.7	0.8
Total				1,927,884	2.0	0.3	1.2
BCUC Approved amount				2,300,000			
Available funds				372,116			

2011					Ratios		
		per participant			PCT	RIM	TRC
Innovative Technologies	**participants**	Incentive ($)	Admin($)	Total($)			
Hydronic Heating Systems	**200**	1000	200	240,000	0.8	0.4	0.3
Alternative Energy systems	**5**	230,000	2000	1,210,435	2.4	0.7	1.1
NGV Vehicles	**32**	50000	500	1,616,000	1.8	0.7	1.4
Residential Groud Source Heat pumps	**67**	3000	200	213,333	0.3	0.7	0.2
Solar Thermal Hot Water	**480**	1000	200	576,000	1.5	0.7	0.8
Total				3,855,768	2.0	0.3	1.2
BCUC Approved amount				4,600,000			
Available funds				744,232			

Innovative Technologies

Terasen Gas

Innovative Technologies Portfolio

Programs	Estimated savings(GJ)	Alternative savings	Measure Life	Total Incremental cost($)
Solar Thermal	14		25	2,325
Commercial Transportation	-1443	32,500 L	22	50,000
Hydronic heating systems	6.2		22	1,100
Residential GSHP Systems	36		25	22,000
Alternative Energy Systems	3000		25	410,000

Proposed Innovative Technologies

TGVI with partner costs included

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.4	0.4	59,854	119,708	$179,562
Commercial NGV	1.4	1.4	167,923	335,847	$503,770
Hydronic Heating Systems	0.4	0.3	24,939	49,878	$74,817
Residential GSHP Systems	0.2	0.2	22,168	44,336	$66,504
Alternative Energy Systems	1.1	1.1	126,774	253,548	$380,322
Portfolio level-TGVI	1.0	1.0	$401,658	$803,317	$1,204,975

Proposed Innovative Technologies

TGI with partner costs included

Programs	TRC Ratios		Program costs		
	2010	2011	2010	2011	Total
Solar Thermal	0.3	0.3	288,000	576,000	$864,000
Commercial NGV	1.5	1.5	808,000	1,616,000	$2,424,000
Hydronic Heating Systems	0.4	0.4	120,000	240,000	$360,000
Residential GSHP Systems	0.2	0.2	106,667	213,333	$320,000
Alternative Energy Systems	1.0	1.1	605,217	1,210,435	$1,815,652
Portfolio level-TGI	1.0	1.0	$1,927,884	$3,855,768	$5,783,652

Terasen Gas EEC Stakeholder Meeting – Stakeholder 2010 Priorities
March 11, 2010

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Greater Vancouver Home Builders' Association	-protecting interests of new home buyers -housing affordability and choice -education -marketing and networking	700+ members Builders Developers Trades Suppliers Architects & designers →Voice of residential construction industry	-reduce/prevent downloading of chares to the price of new homes -promote voluntary market driven green building -underground economy that do not get a permit for renovations	-programs for new home buyers, specifically first –timers -invest in innovative/alternative energy solutions	-continue green incentive programs -educating trades -reno program -consumer behaviour cultural shift -investment for alternative energy solutions
BC Apartment Owners and Managers' Association	-sector sustainability through offering lobbying, education, partnerships with affiliates and associates (price points) -member strength through retention and grown	3000 members Apartment owners & managers (landlords) + associates (suppliers) + affiliates -sustainability	-member education -member retention -member growth -partnership programs to assist members -energy savings; renovations and greener technology -find landlords and hot to reach them	-partnership in education, affiliation, sponsorship -news posts on web, magazine & newsletter -info on present & future opportunities -incentives/split	-workshops and tailor to high rise members, medium buildings, and low rise members -news blasts -intro of new programs -change behavior → how do we make the new "bling" energy efficiency?

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
National Energy Equipment (distributor of Trane)	-increase market creation of home comfort systems for retrofit market -incorporate “clean air” offering into heating and cooling products	-(52) HVAC dealers -homeowners that purchase Trane equipment	-improve quality of installation of Energy Star products -clarify the energy saving message with homeowners	-Terasen dealer (contractor) program -promotions planned outside of the “high season” (Sept –Nov) because impacts quality of installation	-consider “Terasen partners” program on the distribution level (eg. advertising) -work with the NRCan -align upcoming programs with homeowners’ needs and understand consumer mindset
BC Utilities Commission	-increase stakeholder engagement -increase knowledge and capacity in new areas of responsibility, not just an economic regulator		-build capacity/knowledge in commissioners and staff on DSM/energy efficiency best practices from other jurisdictions	-EEC meetings continue -provide updates, feedback and engage with Commission -keep doing what you’re doing	
Consumers Council of Canada	-consumers more aware of energy efficiency options -consumers knowledgeable about the costs/payback/justification of energy efficient purchases -ensure the consumer voice is at the policy table	-residential consumers of energy	-energy efficiency adopted as an objective in building codes -understand consumer attitude to energy efficiency -consumer protection available + accessible to consumers (remedies)	-perhaps a partnership to enable us to get consumers’ opinion/feedback on energy issues + housing issues -access to info on the residential consumer + their preferences & actions (take up of incentives?) -get info to customers	-meet with appropriate Terasen reps to talk about possible options

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Urban Development Institute	-to connect our industry with governments and the public -improve our industry through professional development and education -having a reasonable cost of & regulatory environment for our members	Developers & professionals that support them. -500 corporate members (architects, engineers, banks)	- housing affordability -reducing cost (fees, charges imposed by government -greenbuilding sustainability	-research/education on cost effective green build, energy efficiency, sustainable tools, technologies (how much customers value/do not value on e.e. to potentially support a salesperson education initiative -need consistent approach; various Lower Mainland municipalities are too diverse in policies on sustainable buildings -incentives for our members (green technologies have high upfront costs)	-information -education
Crosby Property Management	-energy savings -green technology	25,000 residential strata owners	-hold costs or do better -looking for incentives -HRTC did a lot in 2009	-information to customers	-timers for fireplaces for strata owners (program)
IBC Technologies	-expand condensing boiler product offering into commercial sizes/markets -more residential market choices with different price points/affordability	-IBC -Canadian Hydronics Council (BC rep) -CSA TC on energy efficiency	-see goals -evolve commercial boiler efficiency measurement standards	-provide clarity on DSM programs and changes thereto -host local roundtable meeting of stakeholders to commercial boiler efficiency issues to take to the national meeting	

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Natural Resources Canada	-improve Canadians' energy consumption practices in commercial and institutional buildings to the end of reduced GHGs (17% by 2020)	Government of Canada	-encourage energy efficiency retrofits and new building design -commissioning and re-commissioning -update energy code -develop bench marketing-data for buildings (offices and schools) -position for transition to post 2011 (funding ending) -build capacity among energy professionals -update the Model National Energy Code for Buildings for release 2012	-information sharing -partnerships/cooperation on optimizing resources in program design/delivery -liaise with regional stakeholders (oversee all of Western Canada)	-develop working groups?
Consolidated Management Consultants	-fair and cost effective supply	-represent commercial energy consumers	-continue to consult with BC Hydro and Terasen Gas -challenge anything that is less than cost effective -success in meeting government's goals-see utilities in succeeding	-consultation on EEC -interested in alternative energy -long term plan for reducing GHGs (by 2050) -interested in cost effective management in utility -continued engagement	
Rate 1 customer/landlord/ New Climate Strategies consultant	-improve energy efficiency infrastructure in my home	-rate 1 customers across BC	-learn about insulation options (for old home) -improve hot water systems - too much waste	-help me assess opportunities in a comprehensive way (not one-off technologies) -expertise for hire, who can assess my options?	-work with BC Hydro to give me coordinated picture of my energy and GHG issues

Organization	**Goals**	**Members represented**	**Priorities for 2010**	**How Terasen can help organization (2-3 ways)**	**Action Item**
Rental Owners and Managers Society of BC	-continue growth to 2400 members -achieve changes to residential tenancy act -increase recognition of rental industry as provider of homes to 1/3 of British Columbian	-2200 residential owners and managers -50,000 rental homes	-increase awareness of ROMS BC among BC's landlords	-recognize distinctiveness & size of residential rental industry +/- 600,000 rental homes -apartment buildings are different from condos or SFDs	-tenants consume, landlords pay??
City of Vancouver	-reduce GHGs -meet community based action goals	-municipality and Vancouver residents	-MURBs and small – businesses -retrofit program (under consideration, require at least 10% of the cost of any permitted renovation to be allocated to e.e. upgrades using prescriptive measures)	-for SFDs – prescribed measures, or Energuide rating -COV support by having green renovation guides online	-example of laneway house with computer interface that indicated energy usage
Ministry of Energy, Mines and Petroleum Resources	-energy efficiency -reducing GHG emissions -develop a culture of conservation		-Energy Plan -Climate action -Clean energy economy	-support for codes and standards -integration with LivesmartBC -innovation with gas (NG vehicles) -communicate with Energuide 80 -go beyond code, maybe home labeling	

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
Tseshaht First Nation	-expand economic development and diversification -expand member employment opportunities -improve quality of life-industry housing -building relationships with Alberni Valley Community	1000 members 750 on reserve	-building 14 new houses (need for 80 families housing—multigenerational, increased growth in community with declining growth in neighbouring community) -7 new RAPS (renovations) -develop partnerships for tourism projects -encourage entrepreneurship -support building of new athletic hall in Port Alberni -new ventures + construction eg. greenhouse	-partnerships for training and mentoring -grants for new athletic hall (gas powered new construction) -seeking appliance bundles for energy efficiency in new houses -cost efficiency and energy efficiency	-do not understand using natural gas on reserve, mainly BC Hydro
Fraser Basin Council	Vision: strong communities, healthy ecosystems and vibrant economies in the Basin and beyond Goals: climate change mitigation/adaptation (reducing GHGs/energy efficiency) -smart planning for communities -regional and sub-regional (local) issue resolution -aboriginal engagement	-all form orders of Canadian government including First Nations + private sector + community/civil society interests	-continue to build on successes: -green fleets BC initiative, transportation -energy solutions for remote communities -supporting community energy planning though BC –demand side management -supply chain Buymost program	-harness power of strategic relationships; facilitate and bring together unlikely parties -multi-interest board	-continuing to build bridges between people, organizations, regions – and action items together

Organization	Goals	Members represented	Priorities for 2010	How Terasen can help organization (2-3 ways)	Action Item
City of Prince George	-climate change goals & objectives that relate to participation in the Partners for Climate Protection Program (PCP). -the goal is a 10% reduction in greenhouse gas emissions from 2012, from a benchmark year of 2002. actively involved in meeting a target of carbon neutral operations by 2012 under the Province's Community Action Charter -20% reduction in overall energy intensity (electricity & natural gas) by 2015 (5 years) -5% reduction in overall energy intensity (electricity & natural gas) for each facility in 2010	-citizens of Prince George	-5% reduction in energy intensity for 2010 -carbon neutral by 2012 -10% Reduction in GHG emissions by 2012	-GHG emissions and energy consumption: easily accessible programs to help decrease GHG emissions, and funding that is available to retrofit old equipment, or implement a project that will decrease natural gas consumption would be appreciated.	

Note: priorities missing from BC Hydro, FortisBC, BC Public Interest Advocacy Centre, Canadian Home Builders’ Association of BC, BC Mechanical Contractors Association, and BC Safety Authority.

Terasen Gas

Terasen Gas EEC Stakeholder Meeting Agenda

Wednesday November 24, 2010
Hyatt Hotel: 655 Burrard St, Vancouver – Grouse Room, 34th Floor

8:50 – 9:00	Registration (coffee served)
9:00 - 9:15	Welcome and Agenda
9:15 – 9:35	TG topic: FortisBC Integration
9:35 – 10:00	TG topic: Natural Gas Vehicle Application
10:00 – 10:10	Break
10:10 – 10:30	EEC 2012 Application
10:35 – 11:45	2010 Programs Review
11:50 – 12:35	Lunch
12:40 – 13:30	Stakeholder Workshop #1, 2011 programs
13:30– 13:45	Break
13:45 – 14:25	Stakeholder Workshop #2, 2011 programs
14:25-14:50	Summary of Workshop Discussions
14:50 – 15:00	Wrap Up and Next Steps

Terasen Gas

Terasen Gas EEC Stakeholder Meeting Minutes
Wednesday November 24, 2010

Attendees
Alison Richter – British Columbia Utilities Commission
Amy Spencer-Chubey – Greater Vancouver Home Builders' Association
Bob Purdy – Fraser Basin Council
Bruce Macgowan – IBC Technologies
Dan Pasacreta – Crosby Property Management
David Craig – Consolidated Management Consultants
Elizabeth Westbrook-Trenholm – Natural Resources Canada
Andrew Pape-Salmon – Ministry of Energy
Jeff Fischer – Urban Development Institute
Jen Richards – City of Vancouver
Mark Hartman – City of Vancouver
Joan Huzar – Consumers Council of Canada
Marg Gordon – BC Apartment Owners and Managers' Association
Keith Veerman – FortisBC
Steve Hobson – BC Hydro, Director Power Smart
Rob Noel – BC Mechanical Contractors Association
MJ Whitemarsh – Canadian Home Builders' Association BC

Regrets
Jim Quail – BC Public Interest Advocacy Centre
Marni Vistisen – City of Prince George, Energy Manager
Al Kemp – Rental Owners and Managers Society of BC
Cindy Stern – Tseshaht First Nation, CEO
Nina Winham – New Climate Strategies; Terasen Gas rate 1 customer
Nir Kushnir – National Energy Equipment, General Manager (Trane)
Wayne Lock – BC Safety Authority, Gas Operations Manager
Brian Jones – Seabird Island

Terasen Gas Staff
Beth Ringdahl
Jenny Chia
Colin Norman
Jim Kobialko
Hakan Kok
Gina Lego
Ned Georgy
Ramsay Cook
Sarah Smith
Mark Grist
Doug Stout

Doug Stout, Corporate Overview (FortisBC Integration)

Question: What is the FortisBC debt/equity ratio?
TG response: 60/40

Mark Grist, Natural Gas Vehicle Program for BC

Question: What is the efficiency of the motors?
TG response: Depends on the engine technology and not the fuel (e.g. heavy duty trucks vs. garbage and transit trucks); for heavy duty trucks, the efficiency can match the efficiency of diesel engines.

Q: Is the carbon tax included in the NGV TRC calculation?
TG: Yes
TG: Terasen is planning to do a workshop in early 2011, to add and monetize additional benefits in the TRC test.

Q: Is there a road tax?
TG: No, not yet. And likely none for the foreseeable future.

Q: What are the different emissions between diesel vs. NGV? For example, particulates, NOx traps. . .?
TG: To meet 2010 emission regulations on diesel engines, manufacturers must install emission controls such as diesel particulate filters and NOx traps. These new additions reduce emissions to levels comparable to NGVs but add cost and reduce the efficiency of diesel engines.

Q: This is the economic thing to do, and the Province is wanting to reduce GHGs – what do you need for a faster transformation adoption?
TG: We are working with the Provincial government to introduce incentive programs to reduce the capital cost barrier. If they contribute funds, this will make the Terasen incentives go further. The Federal government is also looking at tax credits.

Q: What would be helpful from the customers to help this NGV strategy/application?
TG: We do not have approval to provide fueling stations to our customers. Terasen is sending in an application to the BCUC in one to two weeks and additional support, such as letters from the stakeholders, would be appreciated.

Q: Are there safety issues in neighbourhoods?
TG: All fuels have certain risks and appropriate safeguards specific to the specific fuel need to be taken. The risks associated with NG are quite comparable to conventional fuels.

Q: Will a leasing program address the capital cost issue?
TG: Most trucking fleets are leased; hence, we are working on establishing an incentive program specifically designed for leasing situations.
The incentives will also be reduced over time, declining from the existing level of 100% of the incremental cost. We just need to get past the tipping point of adoption (refer to slide 17)

Sarah Smith, EEC Looking Ahead

Question: Is the plan for the application to build from the bottom up again?
TG response: The plan going forward is to ask for funding approval for different areas, but be able to transfer the funds between the different areas within the portfolio if necessary.

TG: Would like input from the group on accountability to ratepayers and stakeholders, for instance we currently have two meetings a year and produce an annual report – is this sufficient? We file our annual report at the end of March (2011) and will ask that any regulatory process relating to the report be deferred to when we file our ask for EEC funding, so that we do not go through two rounds of regulatory process.

Q: What is holding up the mid-efficient furnace change out?
TG: The challenge is that many furnaces are beyond their life cycle. We are looking to do early retirement for furnaces and working with the Ministry of Energy on this issue.

Q: How many programs are explicitly for market transformation? Does Terasen have market transformation plans for their programs?
TG: Not explicitly, however market transformation is one of the Company's EEC Program Principles and most programs are aimed at market transformation. Market transformation should be adopted as a theme for the application for funding approval for 2012, and beyond. One example of a technology where we've launched a program to support market transformation would be the water heater program just launched, and the TLC furnace service program is a market transformation program for behaviour change.

David Craig expressed interest in working with Terasen Gas and BC Hydro for a longer term ask, that is outside of the Revenue Requirement timeframe.

Q: Why is only $10 million of the $30 million budget (for 2010) spent?
TG: We are under spent this year. We underestimated the number of (people) resources required to develop programs and push them out to market. We also have rigorous internal procedures, like developing solid business cases requiring 3 signatures before a program is launched. The rebate funds, however, are not in a holding pattern because we have not been efficient with our application processing. We are looking into simplifying the application process, like putting it on the web for example. If the EEC funds are not used, they are not recovered from ratepayers.

Q: What about using external resources like service organizations and consultants?
TG: We do so when appropriate; we have hired consultants to develop our new construction program, and with our Affordable Conservation program we have several partnerships in place.
BC Hydro: The informed consultant community is also small (limited). We have to compete with other utilities and jurisdictions.
TG: We need to look into building energy efficiency capacity by creating external training opportunities.

Q: In your last application, some of the funds Terasen asked for were reduced, will this happen again?
TG: There were some reductions in our original application, like in the Conservation Education Outreach, but we did get most of what we had asked for. For Innovative Technologies, we re-requested funding approval in our Revenue Requirement application later in 2009.

<u>2011 Programs Workshop – Brainstorming and Discussion</u>

Residential and Conservation for Affordable Housing

<u>Comments on launch of New Construction Program</u>

- Integrate offers with other utility partners or municipalities
- A New Construction Stakeholders Meeting would be beneficial. We need stakeholders' and builders' feedback
- BC Building Code EGH80 introduction is scheduled for November 2011. There are concerns that although builders may be following the prescriptive path through current BC Building Code standards they are not reaching EGH 77 but rather EGH 72-74 is most common. Agreement that Terasen can use EGH 73 for a base line for energy savings calculations since it is a true representation of current industry buildings.
- The EGH80 Nov 2011 new regulations are proposed to focus on improved building envelope standards
- Look at energy specialists into CHBA - 10 Associations already support energy efficiency. How to formalize going forward?
- Cost estimates for EE upgrades are difficult
- Note the regional differences in home performance, costs, upgrades
- Incentivize smaller homes – interesting to look at consumer influences inventory – sell the benefits – is there a potential for small (SPIFFs?) to consumers?
- Municipalities – permit office could distribute program packages (e.g. Saanich, PG, COV)
- Energy Star for Homes is making a comeback (Note CityGreen is administering)
- Nov 2011 new regulation – bundle improved building envelope standards

<u>Tankless Water Heater Program discussion generated a lot of interest</u>

- May be able to add the value of saved floor space into the calculation to help with TRC ; long life span attribution
- Tankless (25-40% savings need to be confirmed)
- North America are laggards in this technology, but need to further understand the 25-40% savings claims in this market
- Survey results are of interest to the group
- 0.80 EF water heater pilot of interest to the group (Jim Kobialko)

<u>Water heaters (storage tanks)</u>

- Increased education for a planned replacement strategy
- TG to look at rentals and financing options
- Clarify efficiency levels with new technology coming to market

<u>Issues in approving programs based on TRC calculations – some ideas</u>

- Look at excluding non-energy related costs from TRC calculations (FortisBC includes this rule in the tariffs)
- Ventilation and carbon monoxide detectors should be considered Enabling Activities that are excluded from TRC calculations.
- Review DSM policy on attribution of savings for all programs and the role of compliance engagement strategies on savings

Affordable Housing Discussion points

- Look at mass purchases for low income: water tanks, furnaces and boilers

Fireplaces

- A lot of discussion regarding need for fireplace programs for MURBs and issues with strata meters and strata policies; Joint program with commercial program manager is under discussion
- Need more customer education on energy use by fireplaces, zone heating/primary/right-sizing, pilot lights and whole home heating

Furnace programs

- Positive feedback for scrap-it program
- TLC Furnace service program success was discussed. Idea for a sticker on furnace for timing of next service

Outreach to TG residential customers & other discussion points

- Explore ways to get unbiased, fuel-neutral, manufacturer-neutral advice to customers
- Need to move beyond energy advisor to advice that is more of a whole-home heating "solution"
- Look at a listserv idea for consumers and the trades to maintain a knowledge base of information and concerns
- How to get the information out to mainstream home/family-based magazines
- Watch for the Canadian Hydronics Council (CHC) upcoming industry advertising campaign "beautiful heat"
  - -essentially gas
  - -alternate energy
  - - focus on health benefits
- Marketing communications could provide more education about why Terasen is involved in conservation:
  - -what's in it for Terasen
  - -what's in it for shareholders
  - -what's in it for customers
- Engage Certified Energy Advisors in promoting programs
- Financing and equipment rentals were discussed briefly. Look to the City of Vancouver program for home retrofits that involves on- tax financing and retrofitting policy
- Consider financing to assist with the deployment of individual metering in Multi-Unit Residential to help promote conservation in suites. Occupants are not readily aware that their gas bills are rolled into strata fees so it is for the common good to reduce their consumption
- Collaborate with key stakeholders on building codes and retrofitting policies. Example, City of Vancouver, Minister Yamamoto, etc.

Commercial

- MURBs – multi-urban residential buildings
- in suite efficiency package, new construction (ie. Terasen option for developers)
- individual metering for stratas
- co funding ad campaigns

Conservation Education

- small business – roundtable (Min. of E. Joy Beauchamp) – Livesmart
- refer to Junior Achievement program
- behaviour change – gov't → Power of 10 gov't buildings
  -bring Terasen in
  -how much control on the gas side?
- behaviour change: continuous optimization program for commercial (on controls)
- 5-10% behaviour energy savings – in commercial
- look at high leverage behaviours (drivers and barriers)
- "social cost of doing nothing"

- new home owner guide/first time home buyer (ie. Terasen hot tips)
- multi-family
- commercial testimonials
- trades students – education, build into training
- school kits as part of curriculum, and take home kits
- industry training – TECA, eg. duct installation problem
- use stakeholder newsletters and channels to promote programs

Portfolio Projects

- energy specialist → program targets (eg. EBP applications)
    - -BC Hydro describes as Sector Enabling
    - -CHBA BA request
    - -CHOA?
- community energy manager → promote programs on a whole
- engage politicians and municipalities – different interests: green, affordability, security, etc.

- CRP findings summary - stakeholder meeting in Jan. 2011
- present to developers (UDI luncheons and important for building codes)
- what technologies pass cost/benefit tests?

- efficiency of model →distributed vs. central model to disseminate information
- compare in-house resources (energy specialists) vs. Terasen EEC solutions managers; in-house seem to get more executive buy-in
- look at supply chain also → procurement, bidding process, etc.

Innovative Technologies and Industrial

- integrated “wireless control system” (eg. dorms, hotels) b/c difference in occupancy levels (Schneider electric)
- heat recover add-ons to rooftop units (Lennox)
- insulation tilt-up concrete buildings , BC (schools)
- solar stack, “glass” space conditions (Manitoba Hydro)
- building architecture
- biomass with Innovative Technologies
- education of technology operations for stakeholders
- Canmet, collaboration studies
- CGA technology

Next Steps

- meeting in March 2011
- getting an industrial and innovative committee member for next EEC meeting

Terasen Gas EEC Stakeholder Meeting

November 24, 2010

FORTISBC | Terasen Gas

Corporate Overview

EEC Stakeholder Meeting

Doug Stout
VP Energy Solutions & External Relations

2.1 million gas and electricity customers

$12 billion assets

FORTIS INC.

- Regulated Utilities
  - FortisBC
  - FortisAlberta
  - Newfoundland Power
  - Maritime Electric
  - FortisOntario
  - Terasen Gas
  - Belize Electricity
  - Caribbean Utilities
  - Turks and Caicos
- Non-Regulated Businesses
  - Fortis Generation
  - Fortis Properties

Fortis in BC: Terasen Gas and FortisBC

- Over one million gas and electric customers
- 135 communities across the province
- Combined assets of $6.4 billion
- Over 1,800 employees
- Have invested $1.03 billion since 2007
- $2.5 billion planned capital investment over next five years

Combined Service Territories

FortisBC

Terasen Gas

Natural Gas Vehicle Program for BC

Mark Grist
Manager, Business Development

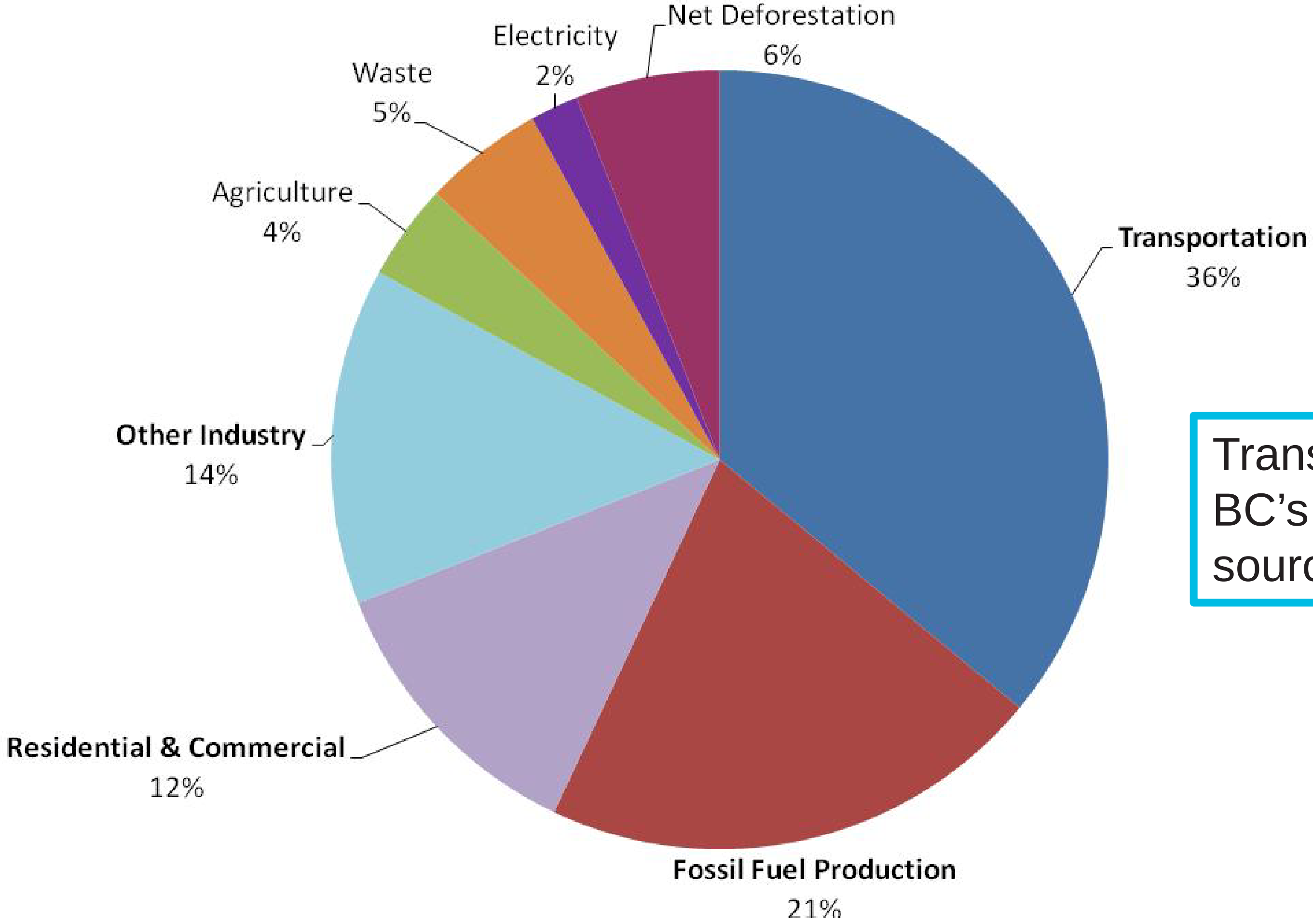
Forward-Looking Statement

By their very nature, forward-looking statements are based on underlying assumptions and are subject to inherent risks and uncertainties surrounding future expectations generally. Such events include, but are not limited to, general economic, market and business conditions, regulatory developments, weather and competition. Terasen and Fortis cautions readers that should certain events or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary significantly from those expected. For additional information with respect to certain of these risks or factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Overview

- Market Context
- NGV Objectives, Strategy & Penetration Estimates
- EEC NGV Incentive Program
- Example Projects & TRC Results
- Non-TRC Benefits
- Energy Security
- Royalty Revenue
- GHG Reductions

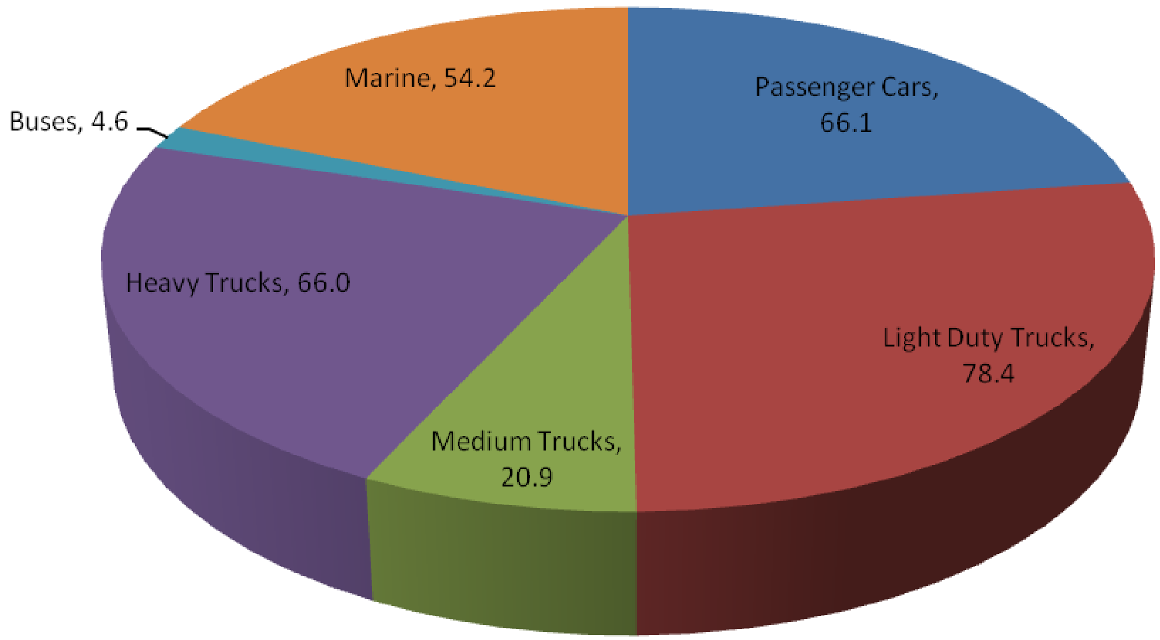
BC’s GHG Emissions by Sector



Transportation sector is BC’s largest GHG source

Source: LiveSmart BC website (2006)

BC's Motor Fuels Market



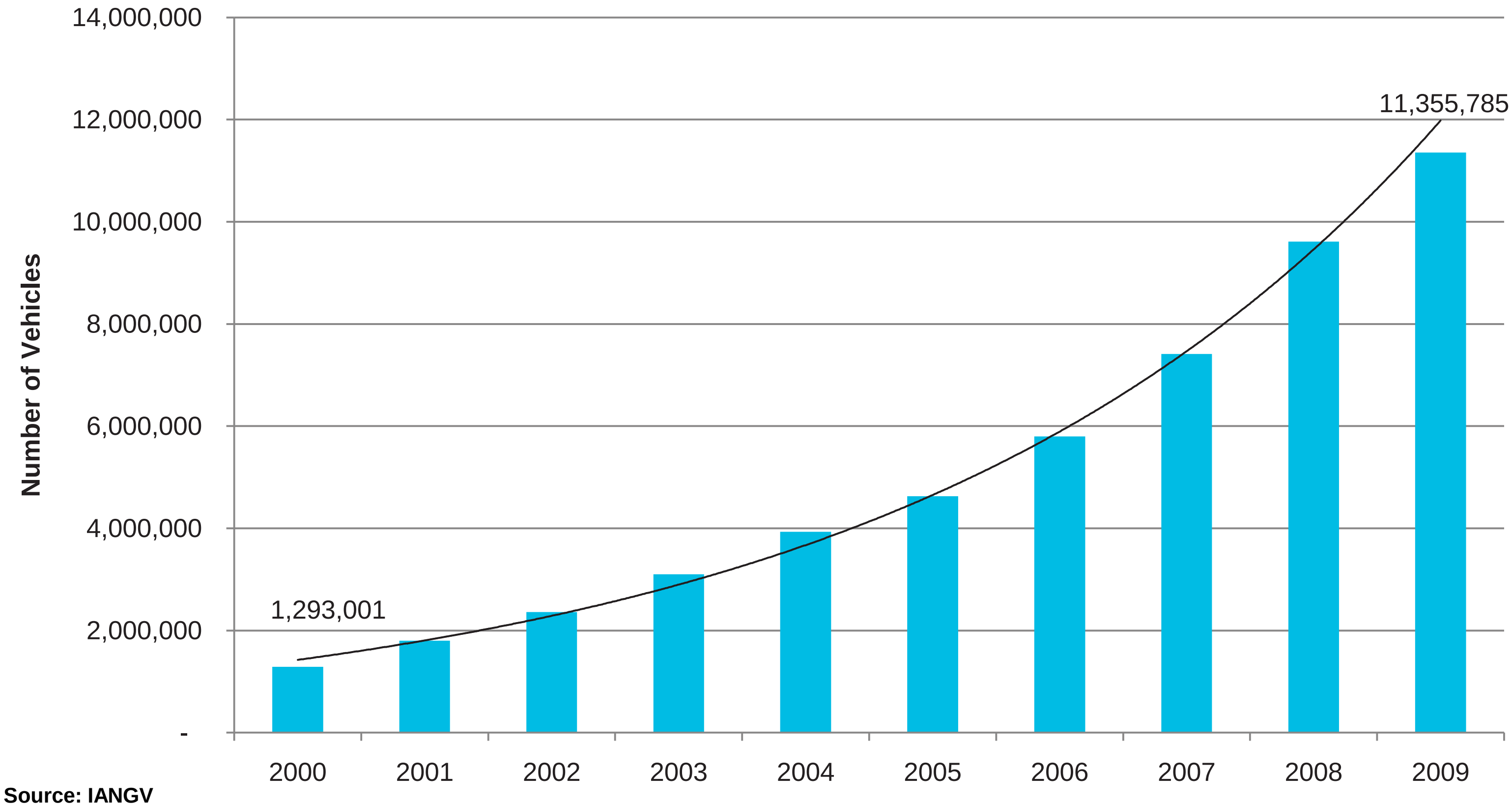
Total : 290.2 PJ
Source: NRCan 2007

Motor fuels market is larger than electricity or natural gas markets in BC

Trucking sector is 57% of total – good target for GHG reductions

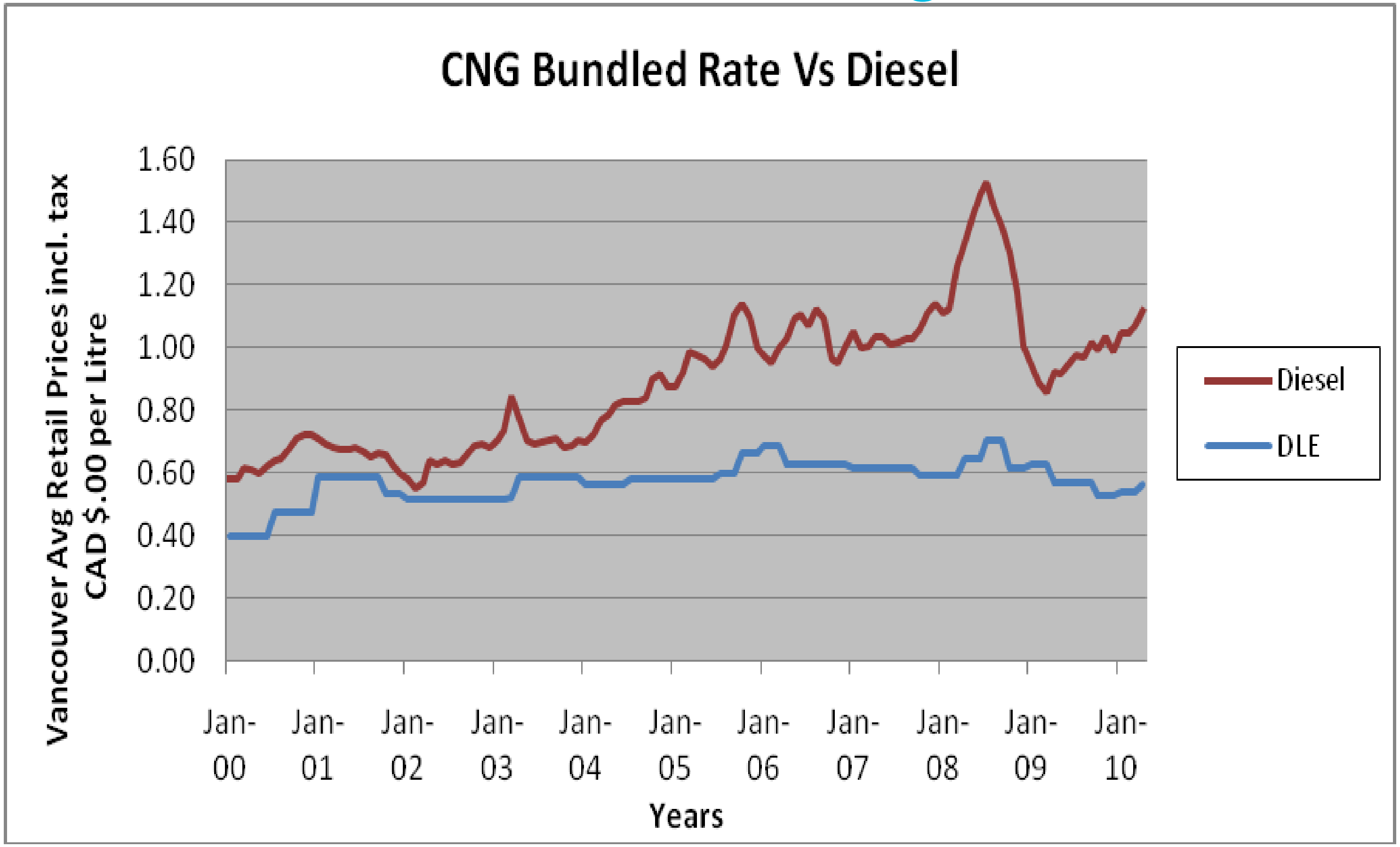
NGVs: A Proven Technology Worldwide

Leading players based in BC



Source: IANGV

Historical Diesel Pricing vs. NG (DLE)



At current pricing NG is 40 to 50% less than diesel

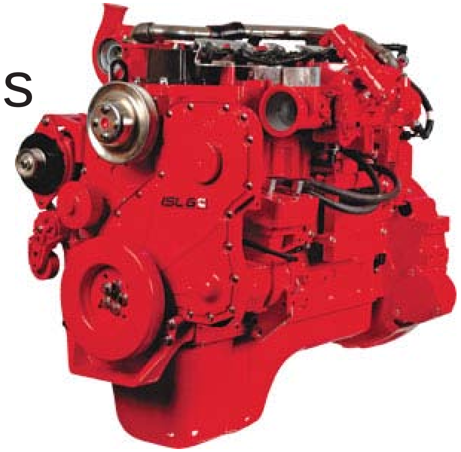
FORTISBC | Terasen Gas

NGV Business Plan Highlights

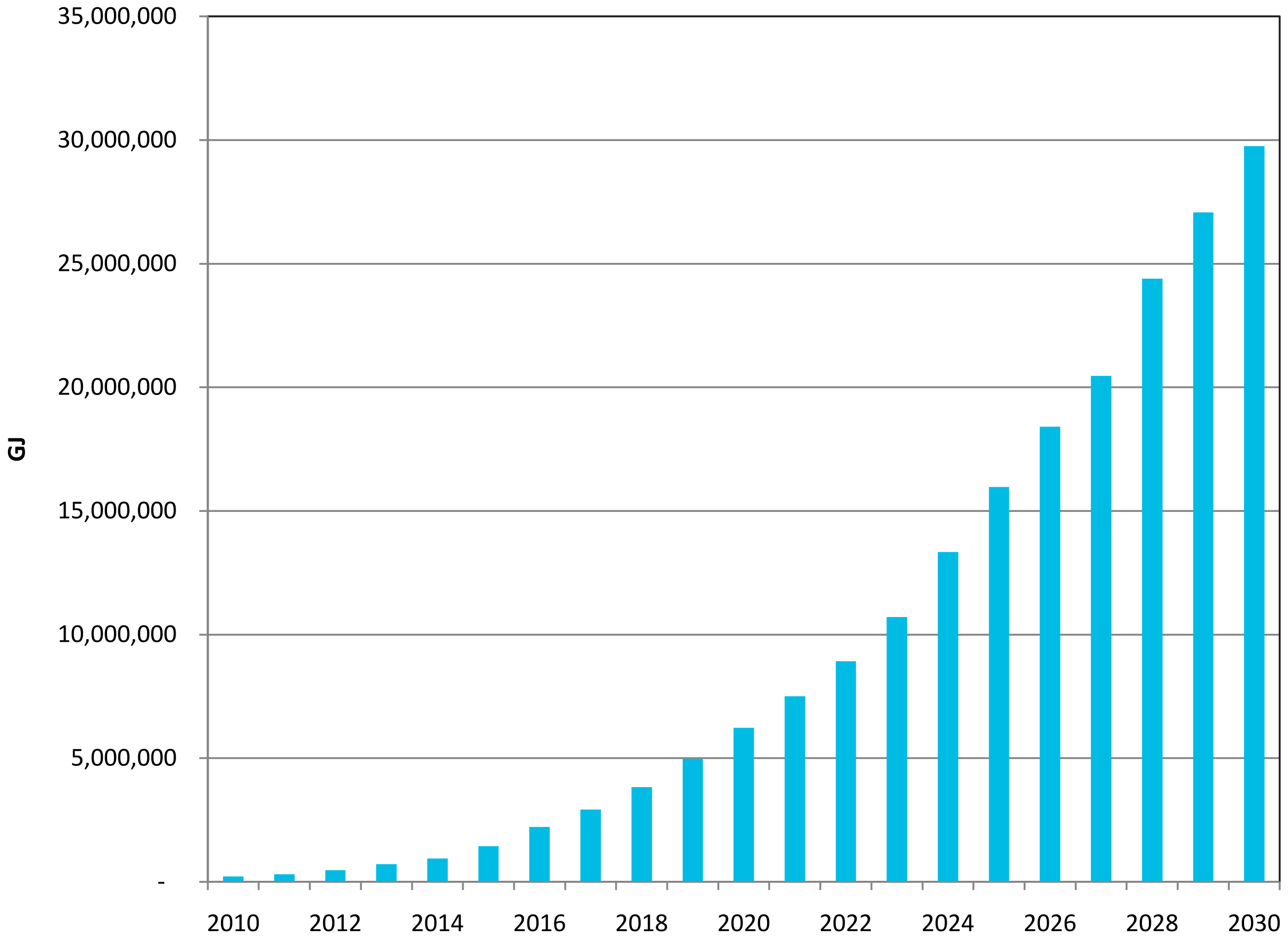
- Achieve 30PJ market penetration by 2030
  - Equivalent to 10% of today's market
  - Roughly equivalent to 15% of Terasen's present system load
- Focus on Heavy Duty Applications
  - Return to base fleets
  - Corridors
- Develop Reference Customers Who Can Ignite Market
  - Leaders in their market segments
- Eliminate Barriers to Adoption
  - Capital cost
  - Fueling infrastructure
  - Vehicle availability

NGV Strategy

- Focus on Heavy Duty Trucks and Transit Buses
- Use Existing NG Engines
- Partner with OEM equipment suppliers
- Support vehicle purchases with incentives



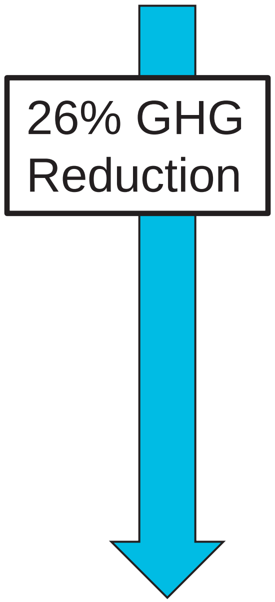
Market Penetration Forecast



Total Target Market Size of 458 PJ by 2030

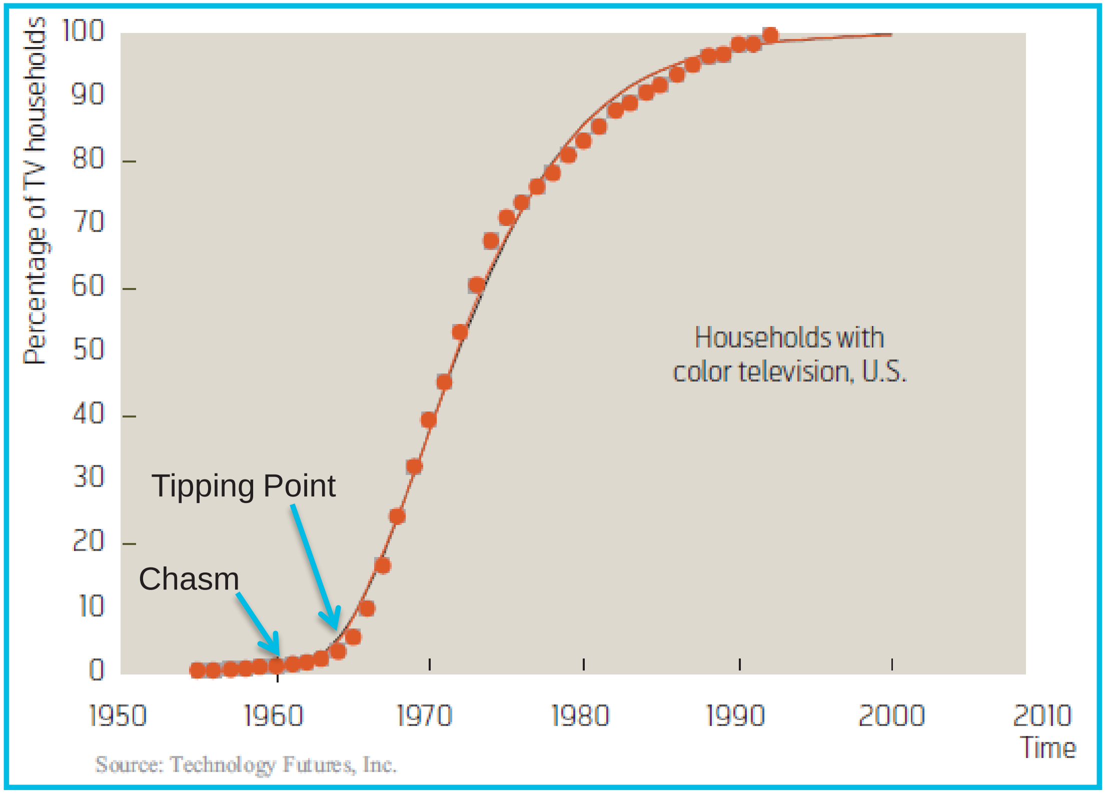
GHG Implications

- 17% of diesel demand can be replaced by natural gas under this scenario by 2030
- GHG savings of 865,000 tonnes CO_2e by 2030
  - Equivalent to displacing 368 million litres of diesel
  - Equivalent to taking 165,000 passenger cars off the road



Market Adoption Curves…

Higher Market Penetration Rates are Probable



New markets follow typical S shaped adoption curve.

Key is getting past "chasm" to "tipping point"

EEC Incentive is Key tool to get past this hurdle

Incentives can decline as market transformation is achieved – final penetration difficult to predict

Everett Rogers – Diffusion of Innovations, 1983

NGVs Delivering Solutions Today

Light Duty Trucks

Port Yard Trucks

Waste Haulers

Transit & School Buses

Urban Work Trucks

Heavy Duty Trucks

Ferries

Lower GHG Emissions with Natural Gas – A Made in BC Fuel

FORTISBC | terasen Gas

NGV Incentive Program

- Covers up to 100% of the incremental cost of the vehicles
- Targeted towards large fleets that run lots of miles
- Generally supports purchases >10 trucks (350,000 litres of diesel)
- Rationale – need scale to pay for fueling infrastructure
- Fueling infrastructure supply not linked to incentive support
- TRC test
- Total cost of incentives and NG fuel vs. cost of diesel
- Does not include GHG or load building benefits
- Commitments to keep vehicles in BC

Terasen Gas Key Projects

Application	Fuel Type	Number of Vehicles	TRC	Displaced Diesel Volume (L/yr)	Annual GHG Savings (tCO2e per fleet)
Garbage truck	CNG	20	1.1	468,000	214
Class 8 tractor	LNG	9	1.0	355,000	213
Class 8 tractor	LNG	25	1.8	5,000,000	3,161
Class 8 tractor	LNG	50	1.2	3,582,850	3,754

Unlike most GHG reduction projects these GHG reductions are achieved at negative cost per tonne of CO2e

The TRC assessments are >1 without factoring in GHG reductions

FORTISBC | Terasen Gas

Additional Upsides

- Load building benefits for all Terasen customers
- Addition of 30 PJ equivalent to 15% increase in load
- Customer benefit estimated at ~ $93 million/year

- GHG Credits
- 865,000 te reduction by 2030
- $21.6 million (@$25/te)

- BC Economy
- Locally produced fuel rather than imports
- Generates production royalties for provincial treasury ($30 million/yr)

Questions?

EEC – Looking Ahead

Sarah Smith
Manager, Energy Efficiency and Conservation

FORTISBC | Terasen Gas

2010 YTD Results

- Portfolio TRC currently 1.1 end Q3
- Projecting $10 million expenditures FY2010
- Cautious pace in growth
- Challenges to rapid expansion of EEC activity
  - Economy
  - Customer Engagement
  - Internal and external resources

2010 EEC Report

- Due March 31 2011
- Any additional content required?
- Regulatory process consolidated with next funding ask

Funding approval request – 2012 and beyond

- How do we ensure EEC resources are focused on efficiency and conservation?
  - Moving beyond the TRC
  - Ability to move funds around
  - Bound by Program Principles
  - Longer term funding approval
  - Funding ceiling
  - Accountability structures

Stakeholder Suggestions: How Terasen can help (March 2010 meeting)	Terasen Action(s)	Program Area(s)	Contact (s)
(relating to new construction) Programs for new home buyers, specifically first –timers Seeking appliance bundles for energy efficiency in new houses For SFDs – prescribed measures, or Energuide rating Support for codes and standards, and go beyond code (eg. home labeling	Quadra Homes pilot Education sessions with GVHBA, CHBAs and other associations Other programs in development	Residential	Beth
Invest in innovative/alternative energy solution	Solar thermal hot water incentives Eg. City of Vancouver	Innovative Technologies	Jim
Partnership in education, affiliation, and sponsorship Partnerships for training and mentoring	In talks with CHBA BC on Built Green Renovator and BC Builder courses ReNEW training program Energy Specialists	Residential Affordable Conservation Portfolio Projects	Beth Ned Colin
News posts on web, magazine & newsletter Info on present & future opportunities	Advertising and outreach through various channels: trade and consumer publications, Terasen bill inserts/newsletters, and call centres	Education – residential and commercial	Jenny
Promotions planned outside of the “high season” (Sept –Nov) because impacts quality of installation	TLC furnace servicing and EnerChoice fireplace programs	Residential	Beth
Perhaps a partnership to enable us to get consumers’ opinion/feedback on energy issues + housing issues	CHBA BC Housing Affordability Symposium	Affordable Conservation	Ned
Incentives for our members (green technologies have high upfront costs)	Solar hot water program	Innovative Technologies	Jim
Host local roundtable meeting of stakeholders to commercial boiler efficiency issues to take to the national meeting	Commercial boiler stakeholder meeting – June 23, 2010	Commercial	Ramsay

Terasen dealer (contractor) program Help me assess opportunities in a comprehensive way (not one-off technologies); expertise for hire, who can assess my options	Existing gas contractor program on Vancouver Island Expansion of gas contractor program on Mainland BC in development Gas contractor newsletters	Efficiency Partners	Gina
Access to info on the residential consumer + their preferences & actions (take up of incentives) Research/education on cost effective green build, energy efficiency, sustainable tools, technologies	Terasen studies: Residential End Use Study Conservation Potential Review Builder/Developer Customer Satisfaction	Residential Research	Beth Colin
Partnerships/cooperation on optimizing resources in program design/delivery Integration with LivesmartBC Harness power of strategic relationships; facilitate and bring together unlikely parties	Currently working on various projects with multiple partnerships and Public Sector Energy Conservation Agreement	Residential Commercial Affordable Conservation	Beth Ramsay Ned
GHG emissions and easily accessible programs to help decrease emissions; funding that is available to retrofit old equipment, or implement a project that will decrease natural gas consumption would be appreciated.	Energy Specialists, funded positions by Terasen Gas for municipalities, hospitals, and school districts Various EEC programs	Portfolio Projects	Colin
Liaise with regional stakeholders (oversee all of Western Canada) Interested in cost effective management in utility	Regional DSM representation Eg. Canadian Gas Association, Northwest Gas Association EEC portfolio	Portfolio	Sarah
Recognize distinctiveness & size of residential apartments and rental industry (+/- 600,000 rental homes)	Fireplace timer pilot program Energy Conservation Assistance Program Energy Saving Kits	Commercial, mult-family Affordable Conservation	Ramsay Ned

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FortisBC EEC Stakeholder Meeting Agenda

March 15, 2011
Coast Coal Harbour Hotel, 1180 West Hastings St, Vancouver, BC – Coal Harbour B

8:45 – 9:00	Registration (coffee and pastries served)
9:00 – 9:30	Welcome
9:30 - 10:30	Presentation: 2010 Annual Report: Highlights and Program Budgets
10:30 – 10:40	Break
10:40– 11:05	Presentation: Conservation Potential Review Study Highlights
11:05– 11:50	Presentation: Total Resource Cost Alternatives and Discussion on Non Energy Benefits
11:50 – 12:45	Lunch
12:15 – 12:45	Presentation: 2012 EEC Funding Application Details
12:45 – 12:50	Wrap Up and Next Steps

FortisBC EEC Stakeholder Meeting Minutes
Tuesday March 15, 2011

Attendees
Marg Gordon – BC Apartment Owners and Managers' Association
Steve Hobson – BC Hydro
Mary McWilliam – BC Non Profit Housing Association
Alison Richter – British Columbia Utilities Commission
Tom Hackney – BC Sustainable Energy Association
MJ Whitemarsh – Canadian Home Builders' Association BC
Craig Williams – Canadian Manufacturers and Exporters
Mike Todd – Canfor Pulp
Stuart Gairns – Canfor Pulp
Mark Hartman – City of Vancouver
David Craig – Consolidated Management Consultants
Joan Huzar – Consumers Council of Canada
Dan Pasacreta – Crosby Property Management
Keith Veerman – FortisBC Inc.
Jim Vanderwal – Fraser Basin Council
Amy Spencer-Chubey – Greater Vancouver Home Builders' Association
Richard Siegenthaler - Hemmera
Bridget Macgowan – IBC Technologies
Chris Frye – Ministry of Energy and Mines
Nir Kushnir – National Energy Equipment
Nina Winham – New Climate Strategies; FortisBC rate 1 customer
Jeff Fischer – Urban Development Institute

Regrets
Leigha Worth – BC Public Interest Advocacy Centre
Erik Skehor – BC Safety Authority
Rob Noel – BC Mechanical Contractors Association
Tony Gioventu – Condominium Home Owners' Association
Gord Monro – Heating, Refrigeration and Air Conditioning Institute of Canada
Al Kemp – Rental Owners and Managers Society of BC
Cindy Stern – Tseshaht First Nation

FortisBC Staff

Beth Ringdahl	Ned Georgy
Jenny Chia	Ramsay Cook
Colin Norman	Sarah Smith
Jim Kobialko	Mark Grist
Hakan Kok	Ryan Findlay
Gina Lego	Shawn Hill

EEC Program Managers, 2010 Annual Report: Highlights and Program Investment Budgets

Question: Didn't we already provide our support of the Natural Gas Vehicle program from the November 24, 2010 presentation?
FortisBC: We require stakeholder support in writing so that we can show the BC Utilities Commission that we have followed the right process in consulting with stakeholders.

Q: What are the savings from the Energy Specialist program?
FortisBC: Enabling Activities do not have any direct energy savings associated with them; however, we will be doing an evaluation of the pilot program later this year.

Jack Habart, Conservation Potential Review Study Highlights 2010
***Note: presentation has not been distributed along with these meeting minutes. The Conservation Potential Review will be filed with the EEC funding application submission in the Spring of 2011.**

Question: Where are the furnaces on the list of residential appliances?
FortisBC: Furnaces do not show up as economically viable with the DSM guidelines set out today, but we know there are thousands of mid to low efficient furnaces still in the marketplace, and we plan to work with government to go after that market potential to change the DSM guidelines, and also discuss a product stewardship strategy.

Question: Why do the furnaces not show up on the graph?
FortisBC: Going from 90-95% efficient furnace is not cost efficient. And right now, we only include economic assumptions, and not behavioural assumptions, such as, people do not always replace their furnace after 18 years (ie. end of useful life).

Question: Do we adjust for this in the base case?
FortisBC: Furnaces do not show up in economic potential, but do show up in achievable potential.

Sarah Smith, 2012 EEC Funding Application Details

Comment: On Joint Initiatives, FortisBC may want to consider keeping a Joint Initiatives category for work with municipalities.

Next Steps

- Annual Report submission to BCUC, March 31, 2011
- EEC funding application, 2012-2013, Spring 2011
- next EEC Stakeholder meeting November 2011

EEC Stakeholder Meeting

March 15, 2011

FORTIS BC™

Agenda

- Welcome and group introductions
- 2010 Annual Report: Highlights and Program Investments
- Conservation Potential Review Study Highlights
- Total Resource Cost Alternatives and Discussion on Non Energy Benefits
- 2012-2013 EEC Funding Application Details

2010 EEC Portfolio Highlights

March 15, 2011

2010 EEC Conventional Portfolio Highlights

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	4,732	5,256	9,988	152,114	1,265,574	0.9
FEVI	727	1,022	1,749	20,706	149,185	1.1
Total	**5,459**	**6,278**	**11,737**	**172,820**	**1,414,759**	**1.0**

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2010 EEC Combined Conventional and Innovative Technology Portfolio Highlights

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	10,548	5,261	15,809	(10,797)	539,178	1.1
FEVI	870	1,022	1,892	22,389	169,030	0.9
Total	**11,418**	**6,283**	**17,701**	**11,592**	**708,208**	**1.1**

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2011 EEC Conventional Portfolio Highlights

Utility	Incentive Expenditure ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	7,772	11,262	19,034	222,383	2,053,338	0.7
FEVI	1,270	2,137	3,407	31,711	268,820	0.6
Total	**9,042**	**13,399**	**22,441**	**254,094**	**2,322,158**	**0.7**

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2011 EEC Combined Conventional and Innovative Technology Portfolio Highlights

Utility	Incentive Expenditures ($000s)	Non-Incentive Expenditure ($000s)	Total for Incentive and Non-Incentive Expenditures ($000s)	Annual Energy Savings (GJ/yr)	NPV Energy Savings (GJ)	TRC
FEI	11,697	11,377	23,074	(3,606)	702,719	1.1
FEVI	1,275	2,148	3,423	31,771	269,539	0.6
Total	**12,972**	**13,525**	**26,497**	**28,165**	**972,258**	**1.1**

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2010 Commercial Programs Investments

Program	Expenditures (Incentive + Non Incentives) ($000s)	Participants (#'s)	TRC
Efficient Boiler Program	$1,315	100	1.4
Public Sector Energy Conservation Agreement (PSECA)	$856	28	2.3
Light Commercial Energy Star Boiler Program	$108	31	1.6
Efficient Commercial Water Heater Program	$22	9	1.1
Energy Assessment Program	$108	68	2.5
Spray N' Save 2010 (Spray Valves)	$16	263 (Valves) 194 Gas / 69 elect	3.9
Fireplace Timer Pilot Program (MURBS)	$10	195 (Timers)	2.3
Total	$2,570	694	1.7

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2011 Commercial Programs Timeline

Program	Q 1	Q 2	Q 3	Q 4
Pre-Rinse Spray Valves				
Commercial Custom Design				
Efficient Boiler Program-revised				
Continuous Optimization				
Commercial Cooking				
Process Heat				
Multi- Unit Residential				

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2010 Residential Customer Programs - Investments

Program	Expenditures (Incentive + Non Incentives) ($000s)	Participants (#'s)	TRC
2009 Furnace Wrap-Up	$2,464	9,648	1.1
Furnace Servicing (eg. TLC)	$511	15,461	N/A
0.62EF Water Heater	$81	172	0.3
EnerChoice Fireplace	$71	135	1.0
LiveSmart BC – Home Audits	$367	4,791	N/A
FortisBC (Electric)	$21	630	2.0
Weatherization Pilot – CoV	$15	50	N/A
Oil/Propane to E* NG Furnace	$300	178	1.4
Total	$4,003	31,065	N/A

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2011 Residential Customer Programs - Timeline

Program	Q 1	Q 2	Q 3	Q 4
0.62 EF Water Tank + E* Tank				
EnerChoice Fireplaces				
LiveSmartBC + Web Portal				
Energy Star Washers				
Furnace Servicing (eg. TLC)				
EnerGuide 80 -New Construction				
Tier 3 (0.80) Water Heater Pilots				
Oil/Propane to E* NG Furnace				

2010 Conservation for Affordable Housing Programs Investments

Program	Expenditures (Incentive + Non Incentives) ($000s)	Participants (#'s)	TRC
Strategic Energy Management Plan (study)	$17	N/A	N/A
Mobile Homes (study)	$10	N/A	N/A
Energy Savings Kits	$104	5,258	2.1
REnEW	$148	59	N/A
Total	$324	5,317	0.8
Ministry of Energy Grant (Super Efficiency New Construction Project)	$515	N/A	N/A

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2011 Conservation for Affordable Housing Programs Timeline

Program	Q 1	Q 2	Q 3	Q 4
REnEW				
Energy Savings Kits				
Energy Conservation Assistance Program (ECAP)				
Mobile Homes Study				
CHF Co-ops Study				

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2010 Innovative Technologies - Investments

- Definition
- Key Objectives
- 2010 Results
- 2011 Planned

Program	Expenditures (Incentive + Non Incentives) ($000s)	Participants (#'s)	TRC
Solar Water Heating PSECA Program	$372	32	0.3

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2011 Innovative Technologies Timeline

2011 Programs	Q 1	Q 2	Q 3	Q 4
Solar BC Schools Incentives				
Solar Air Heating PSECA				

2011 Pilots	Q 1	Q 2	Q 3	Q 4
Solar Residential Hot Water				
Condo Retrofit Pilot				
Occupancy Sensor Pilot				

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2011 Innovative Technologies Timeline

2011 Studies	Q 1	Q 2	Q 3	Q 4
Geoexchange Energy Performance Study				
Lumber Kiln Energy Management Control Feasibility Study				
Solar Wall Shed for Predrying Lumber Prefeasibility Study				

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2010/11 Innovative Technologies - Commercial NGV Demonstration Program

- Objective: encourage heavy duty fleet operators to switch from high-carbon diesel to low-carbon NG
- Benefits: displace diesel fuel, reduce upfront capital cost, environmental benefits and load building benefits
- 2010: $5.6 million for 82 vehicles – 50 LNG and 32 CNG
- 2011: $3.8 million for 54 vehicles – 34 LNG and 20 CNG

Utility (Year)	Participants	Incentive Expenditures ($000s)	Non-Incentive Expenditures ($000s)	Annual Energy Displaced (GJ/yr)	NPV Energy Displaced (GJ)	Free Rider Rate	TRC
FEI 2010 Actual	82	$5,587	$2	(164,665)	(784,502)	0%	1.4
FEI 2011 Forecast	54	$3,780	$1	(228,131)	(1,376,306)	0%	1.9

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Program Area Funding Transfer

- In 2010, $3.487 million transferred from Conventional EEC Program Area into Innovative Technologies Program Area (FEI only)

- Transfer is consistent with Commission Order G-36-09, which allows:

  "…any inter and intra Program Area Initiative funding transfers, with supporting rationale, and the impact of such transfers on the transferor and transferee Program areas, initiatives and measures as the case may be."

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A Speed Bump re the NGV Program…

- Opinion in Interim Ruling on Waste Management
  - *"The Commission Panel is not presently persuaded that Terasen has Commission approval for the incentive grant to Waste Management that is described under Vehicle Reimbursement in the WM Agreement."*
  - *"the Commission Panel believes that Terasen is at risk of not being able to recover Incentive payments to Waste Management in its rates."*

- FortisBC believes that we have express approvals to use EEC funds for NGV initiatives, and have followed the principles and processes defined for the EEC program.

- Clarification of this issue being sought through EEC annual report process

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Sequence of Events
Ongoing Stakeholder Engagement

2008 EEC Application & Decision (G-36-09)
- The Commission denies Innovative Technology and NGV incentives
- Defines program accountability rules

2010- 2011 Revenue Requirement Application
- Approval of EEC funding for Innovative Technologies
- Withdrawal of request for approval of Compression and Fueling Service

2009 EEC Annual Report
- Expansion of Innovative Technologies Portfolio, to include NGV for commercial vehicles for 2010
- Presentation to EEC stakeholders laying out full NGV plan

2010 Resource Plan
- Includes use of EEC funds to promote NGV

Application for CNG and LNG Service
- Interim Decision granting approval of take or pay rate
- Comments made re use of EEC funds

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EEC Accountability Mechanism (G-36-09)

- Proposed Accountability measures:
  - TRC test, Annual Report, Funds not spent not charged etc
  - “Fourth, ….hold annual EEC workshops with stakeholders, at which the companies would present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs.”
- Commission Acceptance
  - “The Commission Panel accepts Terasen’s accountability undertakings…..”

Confusion Re 2010/2011 RRA Decisions

- Two separate and distinct elements
  - EEC Incentive Programs
  - Provision of Compression and Refueling Service
- As part of Negotiated Settlement FortisBC withdrew application for approval of Natural Gas Compression and Refueling Service (postage stamp rate design)
- RRA Negotiated Settlement
  - EEC program, including Innovative Technologies was contained within Negotiated Settlement

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EEC Stakeholder Sessions (2010)

- March 11
  - Presentation of proposed Innovative Tech budget
  - Included budget projections for NGVs
- November 24th
  - Detailed 17 page presentation of NGV program for BC
  - 40% Fuel Savings, 20-30% GHG reductions, Provincial Royalties, $93 million per year in benefits to non-NGV customers (by 2030)
- Stakeholder Feedback
  - No opposition to NGV program
- Conclusion
  - Approach Used is Consistent With Accountability Mechanisms approved for EEC programs

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2010 Application for CNG and LNG Service

- Application relates to providing fueling service, not to providing vehicle incentives
  - Two distinct and separate issues
- Vehicle Incentives are not contingent on purchase of fueling service
  - Customers can pursue other alternatives where available
  - E.g. City of Surrey

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EEC Incentives for NGV: Summary

1
- Meets the cost effectiveness threshold as identified in the original EEC decision and RRA for 2010-2011

2
- Transparency and Stakeholder Engagement (EEC Annual Report, Resource Plan)

3
- Promotes fuel switching from high carbon to lower carbon

4
- Customer uptake and benefits all rate payers (lower delivery rates all else being equal)

5
- Supports the Clean Energy Act and is an example that meets government's GHG emissions reduction objectives (support from Ministry of Energy in FEI RRA for 2010-2011)

FortisBC has express approval to use EEC funds from Innovative Technologies bucket to help fund NGV purchases.

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Business Impacts and Call to Action

- Uncertainty impairs our ability to move forward with business initiatives for CNG & LNG vehicles
- Delays in achieving NGV goals and benefits
  - Climate change – reduction of GHG emissions
  - Load building benefits for all FortisBC natural gas customers
  - Cost reductions for NGV customers
- Market transformation momentum that has taken 2 years to develop is at risk
- Seeking Stakeholder support in getting issue clarified
  - Specifically confirmation that approved process was followed

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2010 and 2011 Industrial Programs

Objective: Create energy efficient plants.

- Energy Audit Funding Program – incentives up to $20,000
- Pulp and Paper Industry Heat Exchanger Pilot Program (Estimated energy savings 70,000 GJ/yr)
- Certified Pilot Plant Project – ISO 50001 "Energy Management Standard". Available in Q3 2011.
- Automated Burner Management System (Mk6 BMS) (Estimated savings 2000 GJ/yr)

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2010 and 2011 Enabling Activities

Energy Specialist Pilot Program

- Currently 14 Energy Specialists in the market
  - 4 more about to be hired
- Evaluation in early Q3 2011
- Progress to date shows successful integration with Energy Manager and large quantity of gas related projects
- Total pilot program investment = $1.2 million

TrakSmart – program tracking

- Initial programs to be launched in TrakSmart in Q2 2011
- Total project investment = $1.4 million

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Enabling Activity: Efficiency Partners Program

2010 Milestones

Research, Communication and Outreach Activity

- Contractor Study undertaken to inform EEC Contractor Program and the LiveSmart BC Program
- Consultation workshops held on Vancouver Island, LM
- Focus group sessions held in the LM
- Established quarterly newsletter
- Outreach to trade associations and organizations

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2011 Efficiency Partners Program Timeline

Planned Activities	Q 1	Q 2	Q 3	Q 4
Contractor Program Launch				
Website development/launch				
Develop/deliver training				
Co-op advertising				

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2010 Conservation Education and Outreach Investments

Program Area (Audience)	Total (Non Incentive) Expenditures ($ 000's)
Residential and General Public Education	$1,118
Commercial Customers Education	$313
Conservation for Affordable Housing Education	$10
Schools	$143
Total	$1,616

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2011 Conservation Education and Outreach Timeline

Planned Activities	Q 1	Q 2	Q 3	Q 4
Home Efficiency Measures	→	→	→	→
Small Business Education Sessions			→	→
BC Housing Tenant Engagement Pilot	→	→	→	→
Post Secondary Program			→	→

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FortisBC
Conservation Potential Review
2010

(please note this presentation has been deleted from the slide deck as the CPR study numbers have not yet been finalized as of March 31, 2011)

Marbek

www.marbek.ca

Addressing the TRC-Carbon Gap

Alternatives to Conventional California B/C Tests for DSM Programs

Prepared for FortisBC

March 15, 2011
Habart & Associates Consulting, inc
CADMUS GROUP, INC

Marbek

www.marbek.ca

Background & Objectives

- FortisBC rapidly expanding initiatives
- Provincial / Federal GHG targets
  - Require aggressive DSM

- Current program screening approaches do not allow adequate investment in EEC programs
  - Project to develop alternate approaches to screening

- Issue occurring in other jurisdictions

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Approach

- Literature review / networking
- Identify Range of Options

- 3 Streams of Discussion:
  1. Change TRC input assumptions
  2. Change screening test
  3. Change approach to B/C testing to better reflect GHG objective

Marbek

GHG Targets
(Residential)

- GHG Reduction Targets
  - BC – 33% below 2007 by 2020
  - Federal – 17% below 2005 by 2020
- BC
  - 1,439 kt CO_2e
  - 28,383 TJ
- Federal
  - 735 kt CO_2e
  - 14,502 TJ
- Residential Economic Potential (2020)
  - 8,260 TJ

Marbek

Current Practice

- California Standard Practices Tests (CST)
  - Total Resource Cost Test (TRC)
    - Balance investment between usage & supply
    - Economic efficiency of energy system
  - Societal Cost Test (SCT)
    - Expands TRC to societal perspective
  - Utility Cost Test (UTC)
    - Perspective of utility
    - Cost of program vs cost of add’t supply
- CST not intended for GHG screening

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Current Practice

- Total Resource Cost Test
  - Conceptually simple, but
    - Assumes consumers are economically rational
    - Assumes non-energy benefits can be quantified / monetized by DSM planners
  - Counter intuitive outcomes
    - Provide incentives for marginally more efficient DWH but no incentive for much more efficient tankless DWH
    - Measure may reduce cost for homeowner, but not pass utility screening if mortgage % < screening %

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Option #1: Change B/C Inputs

- Critical Inputs
  - Avoided / marginal costs
  - Discount rate
  - Free rider / Spillover treatment
  - Treatment of non-energy benefits
  - Program & measure life

#1 - Avoided / Marginal Costs

- The Issue
  - Marginal cost intended to reflect the avoided cost of supply for that measure
- Options & Challenges
  - Utilities often use “average” marginal costs
    - Seasonal marginal costs
      - Summer / flat loads have a different cost than winter
  - Is MC of fossil fuel the “right” screen?
    - Some jurisdictions have higher feed-in rates for green energy
    - CST allows use of higher MC from other utilities
    - FortisBC – MC gas $7.03 vs $9.90 - $15.28 for biogas (2011)

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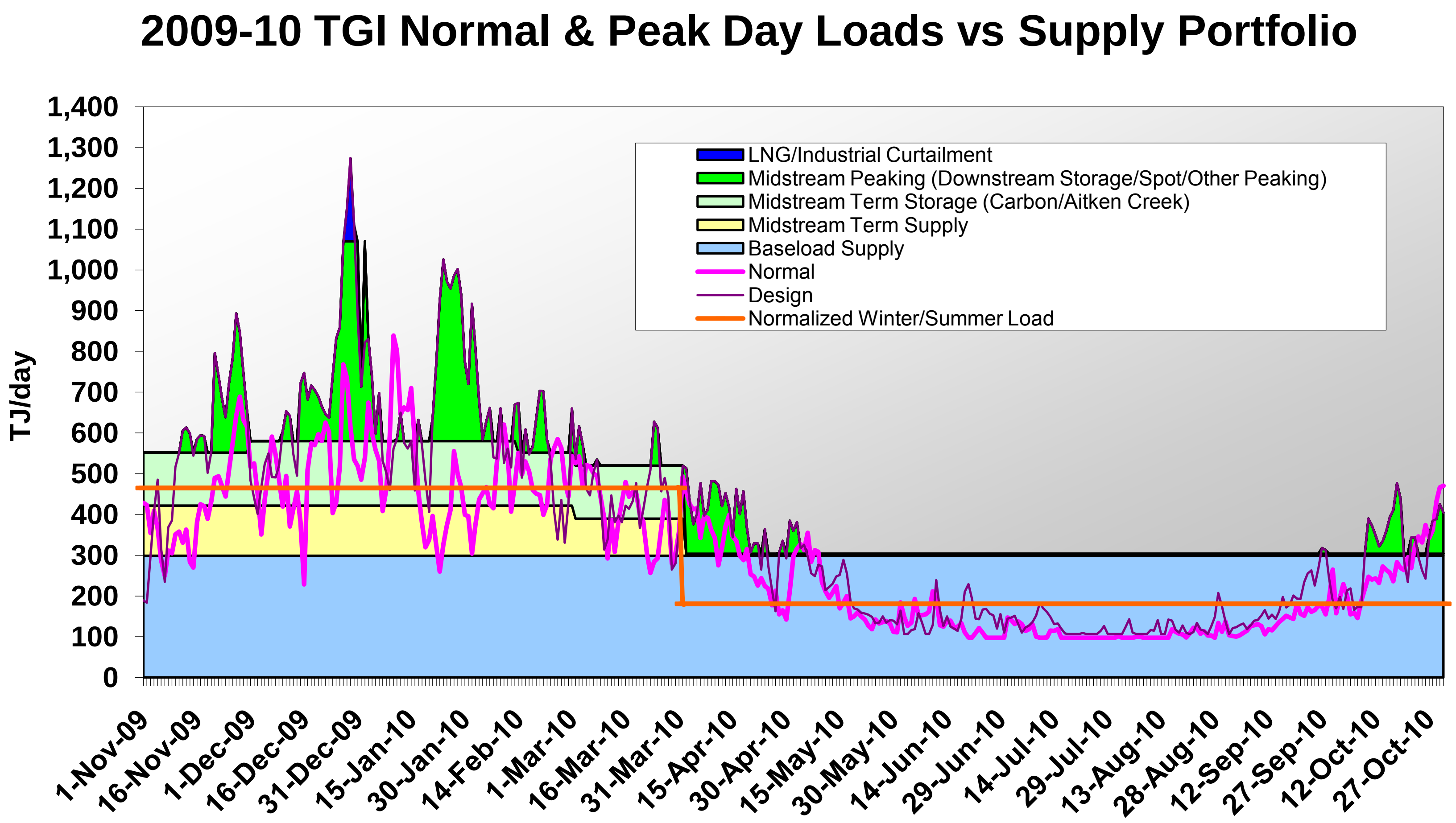
Supply Load Shape



#1 - Avoided / Marginal Costs

- Impact(s)
  - Seasonal marginal costs
    - Not quantified.
  - Marginal cost of biogas (SOC)
    - Possible 40% increase in MC
    - Tankless water heater
      - Base B/C 0.37
      - MC + 40% 0.53

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#1 - Discount Rate

- The Issue
  - High discount rate reduces future benefits
  - TRC specifies weighted cost of capital
    - FortisBC ~ 7.85%
- Options
  - SCT allows the use of a social discount rate
    - Intergenerational equity (ie: building shell > 50 years)
    - Discussion of 2.5 – 3.5% as appropriate in Canada
- Precedents
  - Some US states use Treasury Bill rates (2.5 – 3.5%)
  - US Center of Disease Control uses 3%
  - UK uses 3.5%

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#1 - Discount Rate Impacts

		Discount Rate					
	Measure Life	9.0%	7.0%	5.0%	3.0%	1.0%	0.0%
NPV Measure Benefits @$100 annual benefit stream	5	$389	$410	$433	$458	$485	$500
	10	$642	$702	$772	$853	$947	$1,000
	15	$806	$911	$1,038	$1,194	$1,387	$1,500
	20	$913	$1,059	$1,246	$1,488	$1,805	$2,000
	50	$1,096	$1,380	$1,826	$2,573	$3,920	$5,000
Percentage NPV redution relative to zero discount rate	5	78%	82%	87%	92%	97%	
	10	64%	70%	77%	85%	95%	
	15	54%	61%	69%	80%	92%	
	20	46%	53%	62%	74%	90%	
	50	22%	28%	37%	51%	78%	

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#1 - Discount Rate Impacts

- Impact
  - Tankless water heater
    - Base B/C 0.37
    - 3.5% Disc 0.57

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#1 - Discount Rate Impacts

- Impact
  - Tankless water heater
    - Base B/C 0.37
    - 3.5% Disc 0.57
    - (both) 0.81

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#1 - Free Riders / Spillover

- The Issues
  - Attribute motivations for decisions
    - Free Riders – Would they have done it without the program.
    - Spillover – Installed that / other measures, but no rebate
  - No consensus on “correct” methodologies
    - All methods have biases / provide different results
  - Can add significantly to evaluation time / cost
  - Evaluations tend to focus on FRR, not spillover

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#1 – Free Riders / Spillover

- Options & Challenges
  - Full estimation of both FRR and Spillover
    - Accuracy still uncertain
    - Expensive
  - Assume FRR and Spillover equal out
    - Current practice in some jurisdictions
      - Minnesota, Wisconsin, Oregon, Iowa etc.

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#1 - Free Riders / Spillover (cont'd)

- Impacts
  - Remove significant distraction
  - Reduce cost of evaluations
  - Does require control to avoid "easy, but they would do it anyway" programs
  - For given program if FRR / Spillover understated
    - For society, same energy at same cost
    - More financial burden on non-participants

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#1 - Treatment of Non-energy Benefits

- The Issue
  - Many EEC products not “identical”
  - TRC screening requires EEC planners to determine / monetize non-energy benefits
    - Expensive / arguable
- Options & Challenges
  - Include quantifiable benefits
    - I.e.: labour savings for CFL’s
  - Estimate incremental cost of efficient component(s)
  - Adders for low income programs
  - “Deemed” non-energy benefits?

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#1 - Treatment of Non-energy Benefits

- Impact(s)
  - Likely significant, especially for building shell measures

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#1 - Measure Life

- The Issue
  - Some jurisdictions artificially cap measure life
  - Discount rates negate longer term benefits
- Options & Challenges
  - Use the “best estimate” of measure life
  - Use sensitivity analysis to determine the shortest measure life that provides a positive B/C
  - Focus on discount rates.

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#1 – Measure Life Disc. Impacts

		Discount Rate					
	Measure Life	9.0%	7.0%	5.0%	3.0%	1.0%	0.0%
NPV Measure Benefits @$100 annual benefit stream	5	$389	$410	$433	$458	$485	$500
	10	$642	$702	$772	$853	$947	$1,000
	15	$806	$911	$1,038	$1,194	$1,387	$1,500
	20	$913	$1,059	$1,246	$1,488	$1,805	$2,000
	50	$1,096	$1,380	$1,826	$2,573	$3,920	$5,000
Percentage NPV redution relative to zero discount rate	5	78%	82%	87%	92%	97%	
	10	64%	70%	77%	85%	95%	
	15	54%	61%	69%	80%	92%	
	20	46%	53%	62%	74%	90%	
	50	22%	28%	37%	51%	78%	

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#1 - Program and Measure Life

- Impact(s)
  - Significant with long life / low discount rates

Summary – TRC Changes

- Summary
  - Avoided Cost
    - Biogas ~ +40%
  - Discount Rate
    - Societal discount rate ~ 3.5%
  - Free rider / spillover
    - Not include?
  - Full measure life
    - Significant for building shell etc.

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Option #2: Change B/C Test

- Options - Use
  - Societal Cost Test
  - Utility Cost Test

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Summary of Tests

Elements		TRC	UCT	SCT
Benefits	Avoided Supply Costs	√	√	√
	Avoided T&D Costs	√	√	√
	Bill Reductions (Primary Fuel)			
	Conservation "Adder" or Externalities (Environmental)			√
	Indirect Fuel Benefits	√		√
	Bill Reductions (Indirect Fuel)			
	Other Indirect Benefits			√
Costs	Direct Utility Costs	√	√	√
	Direct Customer Costs	√		√
	Utility Program Administration	√	√	√
	Lost Revenues			
Discount Rate		WACC	WACC	SDR

#2 – Use Societal Cost Test

- Pros
  - Allows use of a societal discount rate
  - Allows the use of higher marginal costs
    - Possible to use MC of biogas?
  - Allows expanded treatment of environmental impacts

#2 – Use Societal Cost Test

- Cons
  - Still screens against the MC of new supply
  - Still requires quantification / monetization of non-energy benefits
  - Does not change issues such as RIM, Free riders/spillover
  - Still requires monetization of environmental impacts
    - May use adders from other jurisdictions

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#2 – Use Societal Cost Test

- Impact on EEC
  - Likely significant for EEC programs
  - Less for GHG

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Summary of Tests

	Elements	TRC	UCT	SCT
Benefits	Avoided Supply Costs	√	√	√
	Avoided T&D Costs	√	√	√
	Bill Reductions (Primary Fuel)			
	Conservation "Adder" or Externalities (Environmental)			√
	Indirect Fuel Benefits	√		√
	Bill Reductions (Indirect Fuel)			
	Other Indirect Benefits			√
Costs	Direct Utility Costs	√	√	√
	Direct Customer Costs	√		√
	Utility Program Administration	√	√	√
	Lost Revenues			
Discount Rate		WACC	WACC	SDR

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#2: Use Utility Cost Test

- Pros
  - More like new supply analysis
  - Avoids non-energy benefits
    - Respects consumers to make choices that provide them value for money.
- Cons
  - Weakens linkage with cost of energy to society
    - Can promote non-cost effective technologies
  - Does not change issues such as RIM, free riders etc
  - Still linked to the MC of new supply
- Used by Michigan / Connecticut

#2: Use Utility Cost Test

- Impact on EEC
  - Can’t model, as only impacts program cost / incentive
  - May not provide sufficient incentive for technologies such as tankless water heaters
    - Incremental cost – $2,400
    - Incremental savings – 6 GJ/yr
    - Value of savings - $1,000

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Summary – Screening Tests

- Summary
  - TRC
    - Screens against cost of new supply
    - Practical limits to DSM investment
  - SOC
    - Greater potential for DSM investment
    - Still screens again cost of new supply
  - UCT
    - Avoids “non-energy benefits”
    - No cost effectiveness boundary

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#3: GHG Based Approach

- The Issue
  - Provincial target is
    - -33% by 2020
    - -80% by 2050
  - Screening against MC of gas likely doesn’t provide sufficient reduction.
    - Use of SCT will improve this.

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#3: GHG Based Approach

- Options & Challenges
  - Screen against value of GHG
    - No agreed value for GHG damage or mitigation
    - May be like valuing environmental benefits
- Alternative
    - Use CPR data to provide a carbon supply curve
    - Determine desired level of carbon reduction & associated costs
    - Negotiate with Government / BCUC for necessary
      - Funding & Approval process

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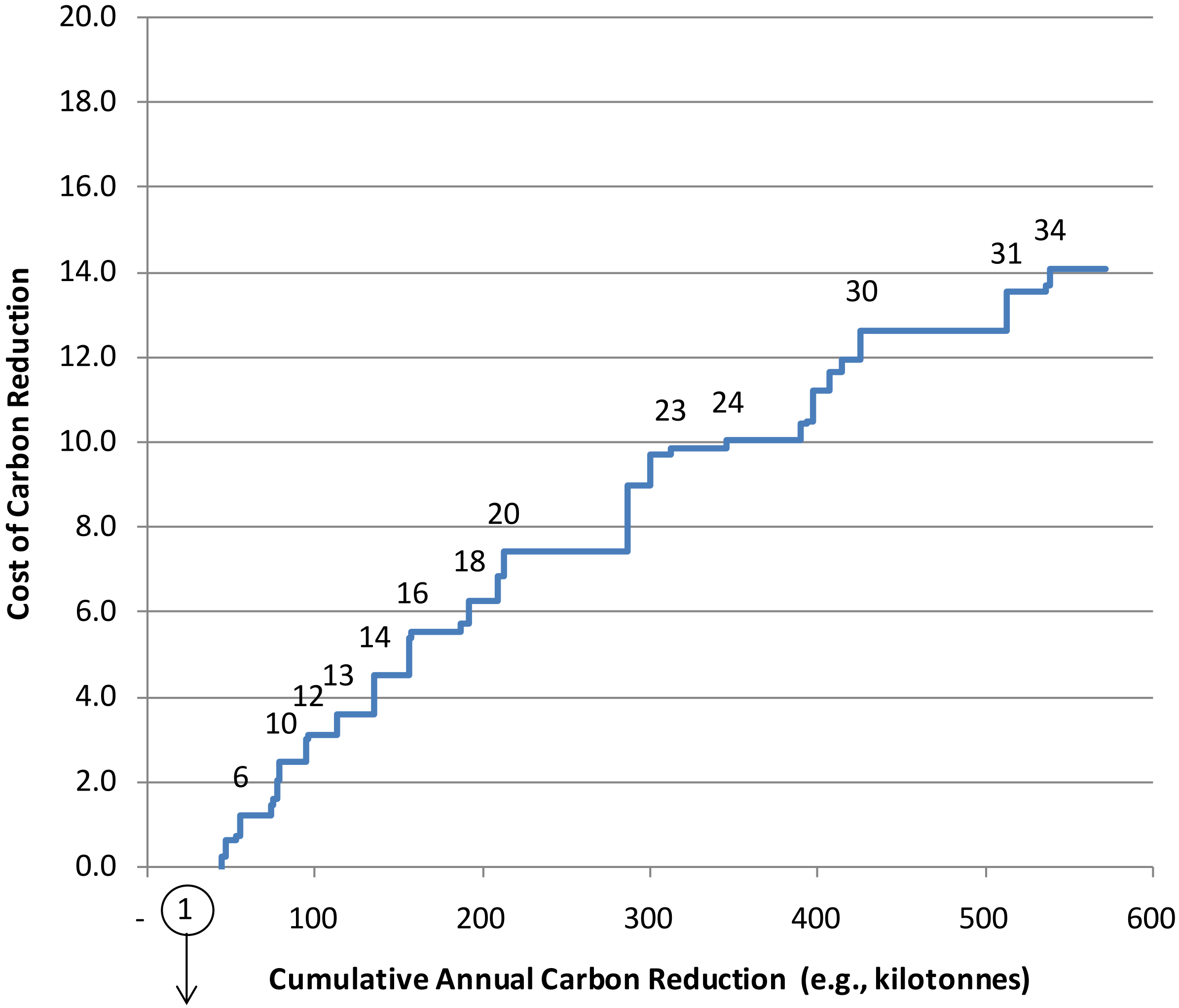
Carbon Reduction Supply Curve

(Concept only)



Carbon Reduction Supply Curve
(Concept only)

- Supply Curve Development Requires
  - CPR Technical Potential
  - Add't Measures that were not screened

- Note:measures lower on the chart are "free"
  - Ie: paid for by DSM savings.

#3: GHG Based Approach

- Pro
  - Provides data to make an informed choice
    - GHG reduction vs. cost / types of initiatives
  - Breaks the link with marginal cost of fossil fuel
  - Directly addresses the GHG policy objective
  - Avoids forecasting MC of gas
- Con
  - Breaks new ground – no precedents
  - Who needs to approve?
  - Who needs to set values / funding?

Thank you

Marbek

2012 - 2013 EEC Funding Application

Sarah Smith

March 15, 2011

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Strategy

- 2012 – 2013 Revenue Requirements Application submission May 2 2011
  - 2 year period
- Long Term Resource Plan submission Summer 2012
  - 20 year planning horizon
  - 5 year EEC funding ask

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Funding approval request – 2012 and 2013

Program Area	2012 ask ($000's) **Total**	2013 ask ($000's) **Total**
Residential	**9,500**	**9,500**
Joint Initiatives	**n/a**	**n/a**
High Carbon Fuel Switching	**1,500**	**1,500**
Low Income	**5,000**	**5,000**
Commercial	**16,000**	**20,000**
Innovative Technology	**12,050**	**17,690**
Conservation Education and Outreach	**5,000**	**5,000**
Industrial	**3,000**	**3,000**
Portfolio Level	**5,000**	**5,000**
Furnace Scrap-It program	**10,000**	**10,000**
Totals	**67,050**	**76,690**

*Note: the numbers are preliminary and could be modified for the Revenue Requirement Application

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Additional Items

- Split 75% FEI, 24% FEVI, less than 1% FEW
- Change in timing of expenditure recovery in rates
- Societal test as primary test
  - Social discount rate
  - Biogas as avoided cost of gas
  - Deemed adder for non-energy benefits
  - Free riders and spillover cancel each other out
  - Exclusion of CEO and Enabling costs from portfolio-level calcs
- Joint Initiatives consolidated with Residential
- EE Financing not included in ask
- S18 programs, with exception of NGV, not included in ask

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FortisBC EEC Stakeholder Meeting – Stakeholder 2011 Priorities
March 15, 2011

Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
Greater Vancouver Home Builders' Association	Protecting interests of new home buyers Housing affordability and choice Education Marketing and networking	700+ members Builders Developers Trades Suppliers Architects & designers →Voice of residential construction industry	Combating the downloading of taxes, fees and levies of homebuyers	Keep us informed about new programs and implementation dates	Let us know what we can do to support funding application
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
BC Apartment Owners and Managers' Association	Sector sustainability through offering lobbying, education, partnerships with affiliates and associates (price points) Member strength through retention and grown	3000 members Apartment owners & managers (landlords) + associates (suppliers) + affiliates -sustainability	Successful energy specialist program Green renovations Dealing with controlled revenue and uncontrollable costs Member relations and growth Education Deal with split incentives Zero rating of HST	Assist energy specialist to promote programs and to have member participation Expand programs to involve BC Hydro programs with our energy specialist. Examine ways to shorten pay-back times Facilitate workshops for our members Cross promotion in each other's communication vehicles	Create a workshop for us on operations and maintenance Assist with tenancy engagement Advertise in BCAOMA communication vehicles and participate in events Assist us with a gas pooling program.

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
National Energy Equipment (distributor of Trane)	Increase market creation of home comfort systems for retrofit market Incorporate "clean air" offering into heating and cooling products	(52) HVAC dealers -homeowners that purchase Trane equipment	Promote consumer education and leverage available programs of energy conservation for new homes and retrofits	Promote homeowners education Provide 2-3 year master plan for stakeholders Explain where and why Fortis is promoting EEC	Establish homeowners online portal Create stakeholder partner program
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
Consumers Council of Canada	Consumers more aware of energy efficiency options Consumers knowledgeable about the costs/payback/justification of energy efficient purchases Ensure the consumer voice is at the policy table	Residential consumers of energy	Consume access to energy efficiency information, both in general and specific to their needs	Support consumers councils proposal to develop the councils energy web pages to make them useful and relevant to consumers	Meet the needs of residential consumers who want to implement energy efficiency measures in their homes Increased support of contractors.

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
Urban Development Institute	To connect our industry with governments and the public Improve our industry through professional development and education Having a reasonable cost of & regulatory environment for our members	Developers & professionals that support them. 500 corporate members (architects, engineers, banks)	Embarking on an Environmental Leadership Initiative (ELI) Affordable housing Communication	Partner with Fortis on ELI Members need more information on district energy, renewable energy, solar, and construction	Would like to do a seminar on District and Renewable Energy. A presentation on Fortis Programs for developers
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
Crosby Property Management	Energy savings Green technology	25,000 residential strata owners	Continued implementation of boiler efficiency program	Good representation in place with Ramsay Cook	

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
Rate 1 customer/landlord/ New Climate Strategies consultant	Improve energy efficiency infrastructure in my home	Rate 1 customers across BC	Weather proofing Assess insulation cost/benefit in older homes Replace aging water heaters	Continue to push "weatherization' as a contractor specialty – consider incentives to increase accessibility/visibility	Help us understand cost/benefit of weatherization and insulation Educate about tankless HW options
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
Fraser Basin Council	Vision: strong communities, healthy ecosystems and vibrant economies in the Basin and beyond Goals: climate change mitigation/adaptation (reducing GHGs/energy efficiency) -smart planning for communities -regional and sub-regional (local) issue resolution -aboriginal engagement	All form orders of Canadian government including First Nations + private sector + community/civil society interests	Action on climate change and air quality Clean water and watersheds Sustainable communities	Partner on outreach to fleets Find ways to link local governments climate plans with Fortis EEC programs	Adjust TRC analysis

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
Canadian Manufacturers and Exporters	Help Canadian Manufacturers and Exporters success in domestic and international markets with a focus on: - Productivity - Energy / Environment - Workplace skills - Business development	Largest economic footprint in BC	Energy Efficiency Programs for Medium Sized Manufacturers	Fund an EE study / implementation program for medium sized manufactures.	
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
BC Non Profit Housing Association	Build sustainable future for non-profit housing in BC.	650 non-profit societies with 1500 buildings	10-20% reduction in natural gas over the next two years Customized incentive programs with Fortis for NP Housing retrofits	Creative incentive programs that fit with unique need of non-profit housing societies Funded energy specialist position as soon as possible Operator training and tools for energy management	Streamlines and bundled incentive programs Increased collaboration with BC Hydro Pilot studies and project M&V – share these as case studies with public or stakeholders

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
Hemmera	Private sector servicing public sector	>3000 client base 144 employees	Expand renewable energy and environmental services to public sector	Provide incentives for feasibility studies and construction at renewable energy projects	Implement societal cost as discount rate base

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
Canfor Pulp	See website	Mike Todd Stuart Gairns	Implementing ECM's already identified	Energy specialist program Incentives based on GJ Savings End use assessments/studies	Roll out energy specialist program

Organization	Goals of Organization	Members represented	Priorities for 2011	How FortisBC can help organization (2-3 ways)	Action Item for FortisBC in 2011
BC Hydro	Pursue cost effective DSM	PowerSmart	Integrated resource plans 2011 DSM targets	Improve consultation on key DSM industry issues before making allegations and proposals to broad audiences that could harm other interests.	
Organization	**Goals of Organization**	**Members represented**	**Priorities for 2011**	**How FortisBC can help organization (2-3 ways)**	**Action Item for FortisBC in 2011**
BC Sustainable Energy Association	Shift BC to 100% sustainable energy use: educate British Columbians on sustainable energy	BC citizens interested in sustainable energy	Green Landlords project Green Condos Retrofit Project	Partner on projects	More energy efficiency

Missing: BC Utilities Commission, IBC Technologies, Consolidated Management Consultants, City of Vancouver, Ministry of Energy and Mines, and Canadian Home Builders' Association of BC

Appendix I

EFFICIENT BOILER PROGRAM TERMS AND CONDITIONS

Efficient Boiler Program

Terms and conditions

Saving you money. We've got our best people on it.

FORTIS BC™

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The incentives

Efficient boiler incentives are made up of two parts: a purchase incentive which is based on the type of boiler purchased, plus either a new construction incentive or a retrofit incentive.

Purchase incentive

For all participants, the incentive applies to the incremental purchase price of a natural gas near-condensing or condensing boiler over the purchase price of a standard-efficiency boiler. The purchase price incentive is based on space-heating and ventilating load. They will be calculated as follows:

- near-condensing boilers: $4,000 per boiler plus $3 per MBH plant input
- condensing boilers: $6,000 per boiler plus $9 per MBH plant input

The purchase price of a standard-efficiency boiler will be estimated using $7 per MBH of the input required to meet the space-heating load.

In addition to the purchase price incentives above, FortisBC will also contribute additional incentives to your upgrade project as outlined below.

New construction

FortisBC will contribute 50 per cent of engineering fees to a maximum of $1,500 toward the cost of estimating the annual gas usage for space-heating using a standard-efficiency boiler system versus a higher efficiency boiler system. Purchase price incentive payments are limited to a maximum of 75 per cent of the purchase price premium over a standard boiler.

Retrofit of existing buildings

The program will pay your contractor up to a maximum of $400 for performing an estimate of the peak space-heating load. It will also pay 50 per cent of the cost of necessary venting modifications up to a maximum of $2,000. During the first year of operation you are also entitled to a monitoring incentive of $1,500 plus $1 per gigajoule of total natural gas saved. Purchase price incentive payments are limited to a maximum of 50 per cent of the purchase price premium over a standard-efficiency boiler.

The benefits

Greater savings

- operating savings from lower energy expenditures
- up to 40 per cent lower fuel costs over a standard-efficiency boiler

Higher performance

- improved operating efficiency through correct boiler sizing

Energy efficiency assistance

- assistance in determining your facility's potential for energy improvements
- help in finding ways to save money and improve your facility's operation

Space efficiency and comfort

- requirement for less space in mechanical rooms
- excellent opportunity to increase occupant comfort and reduce building maintenance

Increased marketability

- improved efficiency appealing to customers who recognize the value it adds to their investment

Environmental benefits

- lower gas usage resulting in fewer CO, CO_2 and NOx emissions
- responsible use of one of the cleanest burning fossil fuels

Program terms and conditions

Note: Subject to change without notice.

1.0 Overview

1.1 The Efficient Boiler Program (the program) from FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc., collectively "FortisBC", is designed to stimulate investment in appropriately sized energy-efficient space-heating boilers that will reduce natural gas usage and associated operating costs. The program is targeted to both new construction and replacement markets.

1.2 The program offers all market participants an incentive payment to partially offset the higher purchase price of higher efficiency boilers, a contribution to the cost of accurately estimating the building's space-heating load.

1.3 In new construction, the program contributes to the engineering fees for estimating the building's annual natural gas usage for space-heating with a standard efficiency boiler and comparing it to that with a higher efficiency boiler. It also partially offsets the higher boiler purchase price incurred by a developer, builder or owner. FortisBC will also recognize the developer's, builder's or owner's commitment to energy efficiency on behalf of tenants, end users and subsequent owners.

1.4 In the replacement market, the program compensates a mechanical contractor to accurately estimate the peak space-heating load. It also reduces the building owner's higher purchase price for an energy-efficient boiler, including an allowance for required venting upgrade modifications. It also promotes proper ongoing operation and maintenance of the heating plant to reduce annual space-heating costs, maintain efficiency and lower life cycle costs by paying building owners a monitoring incentive and a natural gas-saving bonus.

1.5 By taking part in this offer, your boiler may use less natural gas and produce fewer emissions. You agree FortisBC may record any resulting emission reductions you have along with those of other participating customers and credit them to our Greenhouse Gas Management Program.

2.0 Participant eligibility criteria

2.1 The applicant must be a building developer, builder, building owner or owner's designated representative.

2.2 The facility where the boiler is installed must be in the FortisBC service territory in the Lower Mainland, Vancouver Island, Sunshine Coast, or the Interior of B.C. (not available in Whistler).

2.3 The facility where the boiler is installed must use natural gas purchased according to one of the following FortisBC Rate Schedules: 2, 2U, 3, 3U, 23, 5, 25, AGS, SCS-1, SCS-2, LCS-1, LCS-2 or LCS-3.

2.4 Only eligible boilers under the program qualify for the incentive (see Section 4.0 for the boiler eligibility criteria).

2.5 The incentive will only be paid for space-heating boilers. When the boiler is used for space-heating as well as other applications such as domestic hot water and pool heating, the domestic hot water load and the pool heating load will be subtracted from the boiler input to determine the space-heating load for incentive calculations.

2.6 Standby or backup space-heating boiler plants will not normally qualify under this program. Standby or backup boilers are defined as boilers that normally only operate during peak heating load. However, a boiler plant that is not the primary source (i.e., does not provide over 50 per cent) of space-heating for the facility, can qualify if the facility uses natural gas for domestic hot water and make-up air units.

3.0 Program process

All market participants

3.1 Applicant's contractor or qualified professional determines the capacity of the space-heating plant, type of boiler (i.e., condensing or near-condensing), capacity and number of boilers required to meet the space-heating requirements of the building.

3.2 Applicant completes Efficient Boiler Program Application Form and submits it along with required documentation (See Section 7.0) to FortisBC.

3.3 FortisBC reviews application for completeness.

(i) If application is complete, FortisBC estimates the incentive that is payable to the applicant.

(ii) If application is incomplete, FortisBC will ask applicant for additional information.

(iii) If required documents are not completed and submitted within one month of the application date the application may be cancelled.

3.4 Applicant receives a letter from FortisBC stating whether the application was approved or rejected. If approved, an estimate of the incentive(s) payable to the applicant will be attached to the letter.

3.5 Applicant purchases and installs the boiler within 12 months from the date of approval (provided in Section 3.4) by FortisBC.

3.6 Applicant submits required documentation to FortisBC within one month of boiler installation. (See Section 7.0 for documentation.)

3.7 FortisBC reviews documents for completeness.

(i) If all documents are in order and the applicant has met all the requirements of the program and the boiler capacity has not changed from original application, FortisBC issues a boiler incentive cheque to the applicant.

(ii) If all documents are in order and the applicant has met all the requirements of the program, but the installed boiler capacity and/or purchase price has changed since the application was first submitted, FortisBC recalculates the incentive and issues a cheque for the revised boiler incentive.

New construction market participants

3.8 The contribution of FortisBC to the engineering fees required to estimate annual gas usage will be included in the boiler incentive cheque issued to the applicant.

Replacement market participants

3.9. The contributions of FortisBC to the contractor's cost to estimate the peak space-heating load, and to the cost of the required venting upgrades, will be included in the boiler incentive cheque issued to the applicant.

3.10 FortisBC will send the reporting requirements for the monitoring incentive and gas-saving bonus to the applicant with the incentive cheque.

3.11 Applicant prepares the reports that are required for the monitoring incentive and gas-saving bonus.

3.12 Applicant submits the reports to FortisBC. One report is submitted six months after boiler installation; the second report is submitted 12 months after boiler installation.

3.13 FortisBC reviews the reports for completeness.

(i) If applicant meets the reporting requirements, FortisBC calculates the monitoring incentive and gas-saving bonus and issues a cheque. Cheque is issued after FortisBC receives the two complete sequential six-month reports.

(ii) If applicant has not met the reporting requirements, FortisBC advises applicant that reporting requirements have not been met and applicant does not qualify for monitoring incentive and gas-saving bonus.

4.0 Eligible boilers

All boilers

4.1 Must be a natural gas space-heating boiler system (propane boilers in Revelstoke can also qualify). Multiple boiler modules housed in a single jacket constitute one boiler.

4.2 The minimum boiler input rating is 300,000 Btu/hr.

4.3 The maximum boiler input rating is 5,000,000 Btu/hr.

4.4 The minimum space-heating plant input rating is 300,000 Btu/hr.

4.5 The maximum space-heating plant input rating is 10,000,000 Btu/hr.

4.6 The incentive will only be paid for space-heating boilers. (See Section 2.5 for details.)

4.7 Boiler efficiency ratings must be independently tested in accordance with BTS-2000 Testing Standard for Efficiency of Commercial Space-heating Boilers from the Hydronics Institute Division of AHRI (www.ahrinet.org) or CSA 4.9 Gas-Fired Low Pressure Steam and Hot Water Boilers.

4.8 Third-party documentation of boiler combustion efficiencies must be provided for boiler eligibility. Acceptable documentation includes either

- (i) combustion efficiency test reports from testing laboratories accredited by the Canadian Standards Association (CSA International) or the American National Standards Institute or from the Hydronics Institute Division of AHRI;
- (ii) a combustion efficiency certification letter from CSA International; or
- (iii) inclusion in the I=B=R Ratings for Boilers, Baseboard Radiation and Finned Tube (Commercial) Radiation Directory, January 2008 Edition, with the steady state combustion efficiency rating published in the directory (www.ahrinet.org).

4.9 Boiler must be installed in accordance with the manufacturer's specification and must comply with applicable laws, codes, standards and ordinances.

4.10 The boiler must be new. Used or rebuilt boilers do not qualify for the incentive.

4.11 Boilers must be covered by a standard or optional minimum two-year parts and labour warranty.

Near-condensing boilers

4.12 Definition of near-condensing boiler:

- (i) has a minimum steady state combustion efficiency of 85 per cent as tested throughout the turn down range in accordance with BTS-2000[i] or CSA 4.9[ii]
- (ii) has a factory installed intermittent ignition
- (iii) has a forced draft or induced draft burner that properly controls excess air
- (iv) conforming boilers will have continuous capacity modulation (not staged burner output control) to enable AHRI at reduced output down to 50 per cent or less of maximum continuous output. This turndown will be achieved by continuously varying fuel and air input quantities

Condensing boilers

4.13 Definition of condensing boiler:

- (i) has a minimum steady state combustion efficiency of 88 per cent throughout the turn down range as tested in accordance with BTS-2000[i] or CSA 4.9[ii]
- (ii) a Category IV boiler that vents through a Class II Type BH stack or a stack that complies with the manufacturer's recommendations
- (iii) conforming boilers will have continuous capacity modulation (not staged burner output control) to enable operation at reduced output down to 50 per cent or less of maximum continuous output. This turndown will be achieved by continuously varying fuel and air input quantities
- (iv) the boiler can continuously withstand heating system return water temperatures that do not exceed 49°C

List of eligible boilers

4.14 A list of eligible boilers is available on our website at fortisbc.com. This list may be updated during the course of the program.

i - BTS 2000 Testing Standard for Efficiency of Commercial Space-heating Boilers, Hydronics Institute Division of AHRI - 2000

ii - Gas-Fired Low Pressure Steam and Hot Water Boilers, Canadian Standards Association

5.0 Incentives

All market participants

5.1 Boiler purchase price incentives will be calculated as follows:

(i) near-condensing boilers: $4,000 per boiler plus $3.00 per MBH plant input for space-heating load

(ii) condensing boilers: $6,000 per boiler plus $9.00 per MBH plant input for space-heating load

5.2 The purchase price of a standard efficiency boiler will be estimated using $7.00 per MBH of input for space-heating load.

5.3 The boiler purchase price is the applicant's purchase price of the boiler net of any vendor rebates excluding installation labour, venting and accessories.

5.4 FortisBC reserves the right to limit the number of incentive payments it provides for the program.

New construction market participants

5.5 In new construction, FortisBC will pay 50 per cent of a qualified professional's fees to compare the estimated annual natural gas usage for space-heating using a standard efficiency boiler to that with a higher efficiency boiler to a maximum of $1,500. This will be payable to the applicant at the time the boiler purchase price rebate is paid to the applicant and will not be paid unless an eligible boiler is actually installed. Proof of payment must be submitted with the application. The energy modelling must be completed by a qualified professional using DOE, EE4, TRACE, HAP or equivalent program and must compare the space-heating energy use of the building using a standard efficiency boiler and a higher efficiency boiler.

5.6 In new construction, boiler purchase price incentive payments are limited to a maximum of 75 per cent of the premium over a standard efficiency boiler.

Replacement market participants

5.7 In replacement applications, FortisBC will pay a maximum $400 of the cost incurred to estimate the peak space-heating load. This will be payable to the applicant at the time the purchase price incentive is paid and will not be paid unless an eligible boiler is actually installed. Proof of payment must be submitted with the application.

5.8 In replacement applications, boiler purchase price incentive payments are limited to a maximum of 50 per cent of the premium over a standard efficiency boiler.

5.9 In replacement applications, the total amount of the boiler purchase price incentive and the venting replacement incentive is subject to a maximum limit equal to the price of the installed boiler.

5.10 In replacement applications, FortisBC will pay a monitoring incentive of $1,500 plus $1.00/GJ of gas-saving bonus for each GJ of annual weather-normalized reduction in total natural gas consumption. The weather-normalized gas consumption in the 12-month period following the boiler installation will be compared to the weather-normalized gas consumption during the 12-month period prior to the boiler installation. The applicant must report the data from the following inspections:

(i) perform combustion analysis and record combustion efficiency, %CO_2, %O_2, ppm NO_X and flue gas temperature every six months

(ii) perform a diagnostic check of the controls weekly

(iii) perform visual check of system components weekly

(iv) record boiler water outlet temperature weekly

(v) record boiler water inlet temperature weekly

(vi) record boiler room temperature weekly

5.11 Applicant must submit reports that include the data listed above to FortisBC six months and 12 months after the boiler installation to qualify for the monitoring incentive and gas-saving bonus.

Appendix L-1

US GAAP RECONCILIATION

TGI + FT NELSON BALANCE SHEET	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report	TGI Annual Report **Rate Base** (exc. Mid-year)	FNG Annual Report **Rate Base** (exc. Mid-year)	Non Rate Base **/Non Reg**	**Description**
ASSETS									
Current Assets									
Cash & Cash Equivalents	$ 5,710				$ 5,710			$ 5,710	Not included in working capital calculation
Accounts Receivable	$ 277,939	$ 5,909 [1]			$ 283,848			$ 283,848	Not included in working capital calculation
Inventories of Gas in storage and supplies	$ 149,344				$ 149,344	$ 149,326	$ 18		
Prepaid Expenses	$ 2,577				$ 2,577			$ 2,577	Not included in working capital calculation
Future Income Taxes	$ 20,500				$ 20,500			$ 20,500	FIT for financial purposes only
Current portion of Rate Stabilization accounts	$ 68,920				$ 68,920	$ 68,920			
Property, Plant & Equipment	$ 2,373,654	$ 909,812 [2,14,15,16]	$ (82,169) [3,4,5 6,7, 8,10,11]		$ 3,201,297	$ 3,193,151	$ 8,146		
Plant Under Construction	$ -		$ 40,778 [3]		$ 40,778			$ 40,778	WIP
Lower Mainland Acquisition Premium	$ -		$ 176,740 [4]		$ 176,740			$ 176,740	
BCUC Disallowances	$ -		$ 224 [5]		$ 224			$ 224	
SCP CIAC	$ -		$ (64,030) [6]		$ (64,030)			$ (64,030)	
LILO Assets	$ -		$ (109,811) [7]		$ (109,811)			$ (109,811)	
Vehicles leases	$ -		$ 24,729 [8]		$ 24,729			$ 24,729	
Regulated CIAC		$ (164,656) [2,14]			$ (164,656)	$ (163,385)	$ (1,271)		
Intangible Assets	$ 76,100	$ 33,050 [2]			$ 109,150	$ 109,150	$ -		
					$ -				
Investments in and advances to subs	$ 201,622				$ 201,622			$ 201,622	Investments in subs not regulated
Other Assets	$ 339,227	$ (330,180) [9]			$ 9,047			$ 9,047	Not included in working capital calculation
Deferred Charges - (Rate Base)	$ -	$ 74,874 [9]	$ (9,675) [11,12, 20]	$ (35,121) [22]	$ 30,078	$ 30,047	$ 31		
Deferred Charges - (Non-Rate Base)	$ -		$ 8,968 [20]	$ 35,121 [22]	$ 44,089			$ 44,089	Non rate base deferrals and timing adjustments
Future Income Tax	$ -	$ 255,306 [9]	$ 14,653 [10]		$ 269,959			$ 269,959	FIT for financial purposes only
Goodwill	$ -		$ 531 [12]		$ 531			$ 531	Goodwill is non-regulated
Long-term Debt Issue costs	$ -	$ 13,560 [13]			$ 13,560			$ 13,560	Lon-term debt issue costs are non-regulated
TOTAL ASSETS	$ 3,515,593	$ 797,675	$ 938	$ -	$ 4,314,206				
LIABILITIES									
Current Liabilities									
Short term notes	$ 204,000				$ 204,000			$ (204,000)	Debt for financial purposes only
Accounts Payable and Accrued	$ 338,833		$ (1,814) [18]		$ 337,019	$ (25,255)	$ (282)	$ (311,482)	Cash working capital component broken out
LILO Benefits	$ -		$ 1,814 [18]		$ 1,814	$ (1,814)			
Income and other taxes	$ 35,546		$ (1,039) [11]		$ 34,507			$ (34,507)	Tax payable for financial purposes only
Current Portion of Rate Stabilization accounts	$ 11,694				$ 11,694	$ (11,694)			
Future Income Taxes	$ 8,168				$ 8,168			$ (8,168)	FIT for financial purposes only
Current Portion of Long Term Debt	$ 2,232				$ 2,232			$ (2,232)	Debt for financial purposes only
Allowance for Doubtful Accounts		$ 5,909 [1]			$ 5,909			$ (5,909)	Not included in working capital calculation
Long Term Debt	$ 1,590,323	$ 13,560 [13]			$ 1,603,883			$ (1,603,883)	Debt for financial purposes only
Accumulated Depreciation - Gas Plant	$ -	$ 789,186 [2,15,16]	$ (40,335) [4,6,7,8]		$ 748,851	$ (746,818)	$ (2,033)		
Accumulated Depreciation - Lower Mainland Acquisition Premium	$ -		$ 87,547 [4]		$ 87,547			$ (87,547)	
Accumulated Depreciation - SCP CIAC	$ -		$ (16,001) [6]		$ (16,001)			$ 16,001	
Accumulated Depreciation - LILO Assets	$ -		$ (44,780) [7]		$ (44,780)			$ 44,780	
Accumulated Depreciation - Vehicles Leases	$ -		$ 13,569 [8]		$ 13,569			$ (13,569)	
Accumulated Depreciation - Regulated CIAC	$ -	$ (44,716) [2]			$ (44,716)	$ 44,264	$ 452		
Accumulated Depreciation - Intangibles	$ -	$ 33,050 [2]			$ 33,050	$ (33,050)			
Rate Stabilization accounts	$ 23,518				$ 23,518	$ (23,518)			
Other long-term liabilities and deferred credits	$ 149,817	$ (42,797) [17]	$ (9,291) [21]		$ 97,729	$ (97,694)	$ (35)		
Deferred Credits (Non-Rate Base)	$ -		$ 9,291 [21]		$ 9,291			$ (9,291)	Non rate base deferred credits
LILO Deferred Gains	$ -	$ 42,130 [17]			$ 42,130			$ (42,130)	
Construction Advances	$ -	$ 667 [17]			$ 667	$ (667)			
Future Income Taxes (Non-Regulated)	$ 269,871		$ 1,368 [10,19]		$ 271,239			$ (271,239)	FIT for financial purposes only
Future Income Taxes (Regulated)	$ -		$ 609 [19]		$ 609	$ (609)			
EQUITY									
Common Stock	$ 593,959				$ 593,959				
Contributed Surplus	$ 246,501				$ 246,501				
Retained Earnings, opening difference				$ -	$ -				
Retained Earnings, current year-regulated	$ 41,131	$ -	$ 30,827	$ -	$ 71,958				
Retained Earnings, current year-non-regulated		$ 686 [16]	$ (30,827) [25-32,34-38]		$ (30,141)				
TOTAL LIABILITIES + EQUITY	$ 3,515,593	$ 797,675	$ 938	$ -	$ 4,314,206	$ 2,490,354	$ 5,026		
						2489932	5025	amount per annual report	
						$ 422	$ 1	rounding/unexplained	

TGI + FT NELSON
INCOME STATEMENT

	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report	TGI Annual Report Earned Return	FNG Annual Report Earned Return	
REVENUE								
Natural Gas Transmission & Distribution	$ 1,435,416	$ (14,384) [23]			$ 1,421,032	$ 1,415,944	$ 5,088	
Other Operating Revenue	$ -	$ 10,187 [23,33]	$ 10,786 [34,35,36,37,38]		$ 20,973	$ 20,941	$ 32	
Management Fees	$ 7,552	$ (7,552) [24]			$ -			
TOTAL REVENUE	$ 1,442,968	$ (11,749)	$ 10,786	$ -	$ 1,442,005			
EXPENSES								
Cost of natural gas	$ 909,278				$ 909,278	$ (905,678)	$ (3,600)	
Operation and Maintenance	$ 195,026	$ (11,749) [24, 33]	$ (20,593) [25,26,27,28]		$ 162,684	$ (162,026)	$ (658)	
Vehicle Lease costs	$ -		$ 1,804 [29]		$ 1,804	$ (1,804)		
Depreciation & Amortization	$ 72,046		$ (1,252) [29,30,31,32]		$ 70,794	$ (70,632)	$ (162)	
Amortization of intangible assets	$ 9,036				$ 9,036	$ (9,036)		
Property and other taxes	$ 47,750				$ 47,750	$ (47,593)	$ (157)	
TOTAL EXPENSES	$ 1,233,136	$ (11,749)	$ (20,041)	$ -	$ 1,201,346			
OPERATING INCOME (LOSS)	$ 209,832	$ -	$ 30,827	$ -	$ 240,659			
Financing costs	$ 108,313				$ 108,313			
EARNINGS (LOSS) BEFORE INCOME TAXES	$ 101,519	$ -	$ 30,827	$ -	$ 132,346			
Income tax expense (recovery)	$ 17,814				$ 17,814			
NET INCOME (LOSS)	$ 83,705	$ -	$ 30,827	$ -	$ 114,532	$ 240,116	$ 543	
						240050	543	amount per annual report Page 16
						$ 66	$ -	rounding/unexplained
RETAINED EARNINGS								
Balance Beginning of Year	$ 23,926				$ 23,926			
Add: Net Income	$ 83,705	$ -	$ 30,827	$ -	$ 114,532			
Less: Dividends	$ (66,500)				$ (66,500)			
Balance End of Year	$ 41,131				$ 71,958			

TGI + FT NELSON Entries		US GAAP differences
1	Reclass allowance for doubtful account classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
2	Reclass accumulated depreciation classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
3	To recognize Gas Plant under Construction is non-rate base	Classification difference - will continue
4	To recognize Lower Mainland Acquisition Premium is non-regulated	Will continue under US GAAP
5	To recognize BCUC Disallowances are non-regulated	Will continue under US GAAP
6	To recognize SCP CIAC is non-regulated	Wound up in early 201 but would not expect a change under US GAAP
7	To recognize LILO assets are non-regulated	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
8	To recognize Vehicle leases are capital leases for accounting purposes and operating leases for reg purposes	This became a capital for regulatory starting in 2010 so the difference is eliminated already
9	To separate out Deferred Charges and Future Income Tax embedded in other assets in financial statements	Classification difference - will continue
10	To recognize Future Income Tax on CIAC is non-regulated	Will continue under US GAAP
11	To reclass long-term receivable account to bring net of tax balances to a gross basis	Classification difference - will continue
12	To recognize Goodwill is non-regulated	Will continue under US GAAP
13	Reclass unamortized long-term debt issue costs classified as assets for reg purposes and liabilities for financial purposes	Classification difference - will continue
14	To separate out Regulated CIAC embedded in Property, Plant & Equipment	Classification difference - will continue
15	Opening balance adjustment for BC Gas WIP in financial statements not recognized for reg purposes	Will continue under US GAAP
16	Opening balance adjustment for BC Gas assets in financial statements not recognized for reg purposes	Will continue under US GAAP
17	To separate out LILO Deferred gains and Construction Advances embedded in other long-term liabilities in financial statements	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
18	To separate out embedded LILO benefits for regulatory purposes	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
19	To recognize regulated portion of FIT	Will continue under US GAAP
20	To reclassify non-rate base deferred charges	Classification difference - will continue
21	To reclassify non-rate base deferred credits	Classification difference - will continue
22	To recognize timing variances in regulated deferrals per Page 61.8 of annual report	Will continue under US GAAP
23	To separate out other operating revenues per annual report	Classification difference - will continue
24	Management fees reclass done for financial purposes only	Classification difference - will continue
25	To recognize Stock options are non-regulated	Will continue under US GAAP
26	To recognize provision for BioGas costs is non-regulated	Will continue under US GAAP
27	To recognize SCP Financing Lease costs are non-regulated	See above re: scp assets
28	To recognize LILO rent is non-regulated	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
29	To recognize Vehicle leases are treated as operating leases for regulatory purposes	See above re treatment of capital asset portion of capital lease
30	To recognize depreciation on Lower Mainland Acquisition Premium is non-regulated	See above re lower mainland acquisition premium
31	To recognize depreciation on SCP CIAC is non-regulated	See above re scp assets
32	To recognize depreciation on LILO assets are non-regulated	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
33	Rent recoveries reclass done for financial purposes only	Classification difference
34	To remove Earnings Sharing from utility earnings	Will continue under US GAAP
35	To remove equity AFUDC from utility earnings	Will continue under US GAAP
36	To remove LILO gain from utility earnings	Under US GAAP, the financial reporting treatment is expected to change so this different will likely also change
37	To remove GSMIP from utility earnings	Will continue under US GAAP
38	To remove non-regulated gains from utility earnings	Will continue under US GAAP

TGVI BALANCE SHEET	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 1.6	Annual Report Rate Base (exc. Mid-year)	Non Rate Base /Non Reg	Description
ASSETS								
Current Assets								
Cash & Cash Equivalents	$ 10,506				$ 10,506	$ 4,702	$ 5,804	Cash working capital component broken out
Accounts Receivable	$ 31,811	$ 803 [3]	$ 285 [6]		$ 32,899		$ 32,899	Not included in working capital calculation
Due from Related Parties	$ 38				$ 38		$ 38	Investments in subs not regulated
Gas Inventory	$ 9,966				$ 9,966	$ 9,966		
Prepaid Expenses	$ 662				$ 662		$ 662	Not included in working capital calculation
Future Income Taxes	$ 2,832		$ 54,706 [9]		$ 57,538	$ 57,538		
Employee Benefit Plan	$ 1,343	$ (1,343) [4]			$ -			
Gas Plant in Service	$ 537,964	$ 243,372 [1,2]			$ 781,336	$ 781,232	$ 104	TGW common plant allocation double-counted incorrectly in annual report
Gas Plant under Construction	$ 124,025				$ 124,025		$ 124,025	WIP
Non-Rate Base Plant	$ 908	$ 9 [1]			$ 917		$ 917	Non-rate base land and Sooke assets
Unamortized Debt Discount and Expense	$ -	$ 2,177 [7]			$ 2,177	$ 2,177		
Deferred Charges	$ 75,626	$ 5,625 [5]	$ (76,383) [8,9]		$ 4,868	$ 2,033	$ 2,835	Goodwill, VIJV legal costs and Sechelt are non-rate base
TOTAL ASSETS	$ 795,681	$ 250,643	$ (21,392)	$ -	$ 1,024,932			
LIABILITIES								
Current Liabilities								
Short term notes	$ 156,000				$ 156,000		$ (156,000)	Debt for financial purposes only
Accounts Payable and Accrued	$ 44,624		$ (20,440) [6,8]		$ 24,184	$ (1,043)	$ (23,141)	Employee withholdings included in rate base
Due to related parties	$ 2,064				$ 2,064		$ (2,064)	Investments in subs not regulated
Income and other taxes	$ 7,516				$ 7,516		$ (7,516)	Tax payable for financial purposes only
Security Deposits	$ 2,193				$ 2,193	$ (2,193)		
Current Portion of Long Term Debt	$ 24,105			$ (3,575) [10]	$ 20,530		$ (20,530)	Debt for financial purposes only
Allowance for Doubtful Accounts	$ -	$ 803 [3]			$ 803		$ (803)	Not included in working capital calculation
Accumulated Revenue Surplus	$ 8,528			$ 260 [11]	$ 8,788		$ (8,788)	Not part of rate base
Pension Liabilities	$ 5,510	$ (1,343) [4]			$ 4,167	$ (4,167)		
Customer Deposits	$ 289				$ 289	$ (289)		
Accumulated Depreciation - Gas Plant	$ -	$ 194,249 [1]			$ 194,249	$ (194,249)		
Accumulated Depreciation - Non-Rate Base Plant	$ -	$ 9 [1]			$ 9		$ (9)	Depreciation on non rate base plant above
Deferred Credits	$ 1,620	$ 5,625 [5]	$ (392) [9]	$ (260) [11]	$ 6,593	$ (6,349)	$ (244)	Mark to market-LNG in non-rate base deferrals
Long Term Debt	$ 247,823	$ 2,177 [7]			$ 250,000		$ (250,000)	Debt for financial purposes only
Future Income Taxes	$ 55,630		$ (560) [9]		$ 55,070	$ (57,537)	$ 2,467	To recognize non-regulated portion of FIT
EQUITY								
Common Stock	$ 91,977				$ 91,977			
Contributed Surplus	$ 62,259				$ 62,259			
Contributions and Grants (Government Loan)	$ -	$ 49,123 [2]		$ 3,575 [10]	$ 52,698	$ (52,698)		
Retained Earnings, opening difference	$ -			$ -	$ -			
Retained Earnings, current year-regulated	$ 85,543	$ -	$ (6,299)	$ -	$ 79,244			
Retained Earnings, current year-non-regulated	$ -		$ 6,299 [12,13,14,16,17,18]		$ 6,299			
TOTAL LIABILITIES + EQUITY	$ 795,681	$ 250,643	$ (21,392)	$ -	$ 1,024,932	$ 539,123		
						539132	amount per annual report	
						$ (9)	rounding/unexplained	

TGVI
INCOME STATEMENT

	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 1.6	
REVENUE						
Natural Gas Distribution	$ 184,796		$ (3,347) [12]		$ 181,449	
Transportation	$ 24,106				$ 24,106	
Royalty Income	$ 21,891				$ 21,891	
TOTAL REVENUE	$ 230,793	$ -	$ (3,347)	$ -	$ 227,446	
EXPENSES						
Cost of natural gas	$ 103,889			$ (372) [11]	$ 103,517	
Operation and Maintenance	$ 22,309				$ 22,309	
Depreciation & Amortization	$ 22,616		$ (2) [14]		$ 22,614	
Property and other taxes	$ 9,108				$ 9,108	
Wheeling	$ 3,391				$ 3,391	
TOTAL EXPENSES	$ 161,313	$ -	$ (2)	$ (372)	$ 160,939	
OPERATING INCOME (LOSS)	$ 69,480	$ -	$ (3,345)	$ 372	$ 66,507	
Financing costs	$ 16,266		$ (1,305) [13,15]		$ 14,961	Earned Return on Short-term + Long-term debt
Interest on Sub-ordinated Debt	$ -		$ 1,282 [15]		$ 1,282	
EARNINGS (LOSS) BEFORE INCOME TAXES	$ 53,214	$ -	$ (3,322)	$ 372	$ 50,264	
Income tax expense (recovery)	$ 13,262			$ 112 [11]	$ 13,374	
EARNINGS (LOSS) BEFORE REVENUE SURPLUS	$ 39,952	$ -	$ (3,322)	$ 260	$ 36,890	
Revenue Surplus	$ 13,210			$ 260 [11]	$ 13,470	
Higher Rate Base for financial than regulatory	$ -		$ 147 [16]		$ 147	
Special Direction Provision	$ -		$ (1,867) [17]		$ (1,867)	
O&M expense adjustment from actual to allowed	$ -		$ 4,697 [18]		$ 4,697	
NET INCOME (LOSS)	$ 26,742	$ -	$ (6,299)	$ -	$ 20,443	Earned Return on Equity

RETAINED EARNINGS

	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 1.6
Balance Beginning of Year	$ 79,301				$ 79,301
Add: Net Income	$ 26,742	$ -	$ (6,299)	$ -	$ 20,443
Less: Dividends	$ (20,500)				$ (20,500)
Balance End of Year	$ 85,543				$ 79,244

TGVI Entries	US GAAP differences
[1] Reclass accumulated depreciation classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
[2] Reclass Contributions and Grants classified as equity for reg purposes and asset for financial purposes	Classification difference - will continue
[3] Reclass allowance for doubtful account classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
[4] Reclass employee benefit plan classified as liability for reg purposes and asset for financial purposes.	Classification difference - will continue
[5] Reclass GCVA classified as liability for reg purposes and asset for financial purposes.	Classification difference - will continue
[6] Reclass Royalty Revenue receivable classified as liability for reg purposes and asset for financial purposes.	Classification difference - will continue
[7] Reclass unamortized long-term debt issue costs classified as assets for reg purposes and liabilities for financial purposes	Classification difference - will continue
[8] Ineffective hedges relating to cost of gas for financial purposes only	Will continue under US GAAP
[9] Non-regulated FIT for financial purposes only (FIT included on Reg schedules beginning 2010).	Will continue under US GAAP
[10] Government loan reclass-timing. Booked in Reg books in 2009, financial books in 2008.	Will continue under US GAAP
[11] GCVA adjustment-timing. Booked in Reg books in 2009, financial books in 2010.	Will continue under US GAAP
[12] To recognize AFUDC-Equity is non-regulated	Will continue under US GAAP
[13] To recognize Interest on Goodwill is non-regulated	Will continue under US GAAP
[14] To recognize depreciation on Sooke assets is disallowed	Will continue under US GAAP
[15] To recognize interest on sub-ordinated debt is non-regulated	Will continue under US GAAP
[16] To recognize that rate base for financial purposes is higher than rate base for Reg purposes	Will continue under US GAAP
[17] Special Direction provision dis-allowed for Reg purposes	Will continue under US GAAP
[18] To adjust O&M from actual to allowed for Reg purposes	Will continue under US GAAP

TGW

BALANCE SHEET	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 1.6	Annual Report Rate Base (exc. Mid-year)	Non Rate Base /Non Reg	Description
ASSETS								
Current Assets								
Accounts Receivable	$ 2,324	$ 40 [2]		$ 4 [7]	$ 2,368	$ 64	$ 2,304	Cash working capital component broken out
Due from Related Parties	$ 1,094				$ 1,094		$ 1,094	Investments in subs not regulated
Future Income Taxes	$ 326		$ (326) [3]		$ -			
Gas Inventory	$ -		$ 337 [4]		$ 337	$ 337		
Property, Plant & Equipment	$ 13,196	$ (1,409) [1]		$ 4,368 [15]	$ 16,155	$ 16,011	$ 144	WIP
Intangible Assets	$ 83				$ 83	$ 83		
Deferred Charges	$ 30,739		$ 4,867 [3,5]	$ (4,171) [6,15]	$ 31,435	$ 29,548	$ 1,887	Pipeline development costs in non-rate base deferral
TOTAL ASSETS	$ 47,762	$ (1,369)	$ 4,878	$ 201	$ 51,472			
LIABILITIES								
Current Liabilities								
Accounts payable and accrued liabilities	$ 200		$ 337 [4]		$ 537	$ (47)	$ (490)	Employee withholdings included in rate base
Income and other taxes payable	$ 173			$ 1 [7]	$ 174		$ (174)	Tax payable for financial purposes only
Due to related parties	$ 7,680				$ 7,680		$ (7,680)	Investments in subs not regulated
Deferred credits	$ 1,800				$ 1,800	$ (1,800)		
Customer deposit	$ 117				$ 117	$ (117)		
Allowance for Doubtful Accounts	$ -	$ 40 [2]			$ 40		$ (40)	Not included in working capital calculation
Accumulated Depreciation - Gas Plant	$ -	$ (1,409) [1]			$ (1,409)	$ 1,409		
Long-term advance due to parent	$ 20,000				$ 20,000		$ (20,000)	Investments in subs not regulated
Deferred credits	$ 797		$ (550) [5]	$ (48) [7,8,9]	$ 199	$ (199)		
Future income taxes	$ 1,414		$ 254 [3,5]		$ 1,668	$ (1,668)		
EQUITY								
Share capital	$ 16,671				$ 16,671			
Retained Earnings, opening difference	$ -			$ 43 [10,11,12]	$ 43			
Retained Earnings, current year-regulated	$ (1,090)		$ 4,564	$ 205	$ 3,679			
Retained Earnings, current year-non-regulated	$ -		$ 273 [13,14]		$ 273			
TOTAL LIABILITIES + EQUITY	$ 47,762	$ (1,369)	$ 4,878	$ 201	$ 51,472	$ 43,621		
						$ 43,622	amount per annual report	
						$ (1)	rounding/unexplained	

TGW
INCOME STATEMENT

	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 12.0	
REVENUE						
Natural gas and propane distribution	$ 15,434		$ (136) [14]	$ 308 [6,9,12]	$ 15,606	
TOTAL REVENUE	$ 15,434	$ -	$ (136)	$ 308	$ 15,606	
EXPENSES						
Cost of natural gas and propane	$ 10,020				$ 10,020	
Operation and maintenance	$ 6,560		$ (5,860) [3]		$ 700	
Depreciation and amortization	$ 434				$ 434	
Property and other taxes	$ 369				$ 369	
Wheeling	$ 1,995				$ 1,995	
TOTAL EXPENSES	$ 19,378	$ -	$ (5,860)	$ -	$ 13,518	
OPERATING (LOSS) INCOME	$ (3,944)	$ -	$ 5,724	$ 308	$ 2,088	
Financing costs	$ 1,022			$ 68 [8,10,11]	$ 1,090	Earned Return on Short-term + Long-term debt
(LOSS) EARNINGS BEFORE INCOME TAXES	$ (4,966)	$ -	$ 5,724	$ 240	$ 998	
Income tax (recovery) expense	$ (1,393)		$ 1,160 [3,13]	$ 35 [7,8,9]	$ (198)	
NET (LOSS) INCOME	$ (3,573)	$ -	$ 4,564	$ 205	$ 1,196	Earned Return on Equity

RETAINED EARNINGS

	Financial	Reclasses	Reg Differences	Timing Differences	Annual Report Page 12.0
Balance Beginning of Year	$ 2,483				$ 2,527
Add: Net Income	$ (3,573)	$ -	$ 4,564	$ 205	$ 1,196
Balance End of Year	$ (1,090)				$ 3,723

TGW Entries	**US GAAP differences**
[1] Reclass accumulated depreciation classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
[2] Reclass allowance for doubtful account classified as liability for reg purposes and asset for financial purposes	Classification difference - will continue
[3] Provision for conversion costs booked for financial purposes only	Will be adjusted in 2010 based on BCUC decision
[4] Allocate Gas Inventory from TGI for reg purposes only	Will continue under US GAAP
[5] Non-regulated FIT for financial purposes only (FIT included on Reg schedules beginning 2010).	Will continue under US GAAP
[6] Income tax on conversion costs-timing. Booked in Reg books 2009, financial books 2010.	See comment above
[7] Gas sales correction-timing. Booked in Reg books 2009, financial books 2008.	Will continue under US GAAP
[8] 2009 Short-term debt adjustment-timing. Booked in Reg books in 2009, financial books in 2010.	Will continue under US GAAP
[9] 2009 ROE adjustment-timing. Booked in Reg books in 2009, financial books in 2010.	Will continue under US GAAP
[10] 2008 Short-term debt adjustment-timing. Booked in Reg books in 2008, financial books in 2009.	Will continue under US GAAP
[11] 2008 ROE adjustment-timing. Booked in Reg books in 2008, financial books in 2009.	Will continue under US GAAP
[12] 2008 Long-term debt adjustment-timing. Booked in Reg books in 2008, financial books in 2009.	Will continue under US GAAP
[13] To recognize difference in regulated vs. non-regulated income tax expense	Will continue under US GAAP
[14] To recognize AFUDC-Equity is non-regulated	Will continue under US GAAP
[15] Loss on disposal of propane assets. Transferred in Reg books in 2010, financial books in 2009.	Will continue under US GAAP

Appendix L-2

CORPORATE SERVICES AMENDING AGREEMENTS
EFFECTIVE JANUARY 1, 2012

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY INC.
(formerly Terasen Gas Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas Inc." and "TGI" shall be deleted and replaced with "FortisBC Energy Inc." and "FEI" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $10,719,700 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $11,030,900 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY INC.

By: ____________________

Roger Dall'Antonia

Title: Vice President, Finance & CFO

FORTISBC HOLDINGS INC.

By: ____________________

Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEVI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEVI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas (Vancouver Island) Inc." and "TGVI" shall be deleted and replaced with "FortisBC Energy (Vancouver Island) Inc." and "FEVI" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEVI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $1,140,100 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $1,196,300 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

By: ______________________

Roger Dall'Antonia

Title: Vice President, Finance + CFO

FORTISBC HOLDINGS INC.

By: ______________________

Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (WHISTLER) INC.
(formerly Terasen Gas (Whistler) Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEW")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEWI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas (Whistler) Inc." and "TGW" shall be deleted and replaced with "FortisBC Energy (Whistler) Inc." and "FEW" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEW agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $48,500 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $50,200 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (WHISTLER) INC.

By: ______________________

Roger Dall'Antonia

Title: Vice President, Finance & CFO

FORTISBC HOLDINGS INC.

By: ______________________

Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

Appendix L-3

FEI-FBC MUTUAL SHARED SERVICES AMENDING AGREEMENT EFFECTIVE JULY 1, 2010

MUTUAL SHARED SERVICES AGREEMENT

THIS AGREEMENT is made effective the 1st day of July, 2010.

BETWEEN:

FORTISBC ENERGY INC., a corporation formed under the laws of British Columbia having an office at 1000-1111 West Georgia Street, Vancouver, British Columbia, V6E 4M3

(hereinafter "FEI")

AND:

FORTISBC INC., a corporation formed under the laws of British Columbia, having an office at Suite 100, 1975 Springfield Road, Kelowna, British Columbia, V1Y 7V7

(hereinafter "FBC")

WHEREAS

A. FEI and FBC are both wholly owned subsidiaries of Fortis Inc.

B. FEI and FBC each require certain services on an as required basis.

C. FEI and FBC are each willing to provide the Services to the other on the terms and conditions contained in this Agreement.

WITNESSETH THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the performance of the Services hereunder;

(b) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasigovernmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(c) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(d) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(e) "**Services**" means the professional and management services to be provided by FEI or by FBC respectively, as required by the each of the parties from time to time.

1.2 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,
2) any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement,
3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,
4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,
5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Canadian utility industry, shall have such accepted meaning.

1.3 Governing Law

Subject to Section 7.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

Each party hereby agrees to provide to the other the Services on an as required basis and to the extent the party providing the Services has the capacity, as determined by it in its sole discretion, to provide such Services.

2.2 No Obligation to Provide Additional Services

Neither party shall perform, and shall have no obligation to perform, any services to the other except as set out in this Agreement or any similar agreement.

2.3 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between FEI and FBC. In performing the Services, each party shall be an independent contractor. FEI employees and FBC employees shall not be considered employees of the other party for any purpose.

2.4 Compliance

In performing the Services, each party will comply with all Applicable Laws and its own applicable standards and policies.

2.5 Confidentiality

The party providing the Services will comply with confidentiality or non-disclosure agreements between the party receiving the Services and any other Person with respect to information required for the Services. Each party waives any right of confidentiality as between the two parties with respect to any information provided by such party to the other party's employees in the course of providing Services.

2.6 Protection of Personal Information

The party providing the Services will comply with any protection of personal information policy of the party receiving the Services.

PART 3

COMPENSATION

3.1 Compensation for Services and Shared Costs

The party receiving Services agrees to reimburse the party providing Services for all reasonable expenses it has incurred in providing such Services, including, without limitation, such portion of the annual salary and benefits of relevant employees as is determined by the party providing Services to be allocable to the party receiving Services based on the nature and extent of Services actually provided during the applicable period.

3.2 Invoicing

The party providing Services will invoice the other in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.3 Payment

(a) Except with respect to those portions of an invoice which are the subject of a bona fide dispute between the parties, the party receiving Services shall within thirty (30) days after receipt of an invoice from the party providing Services, pay the amount specified in such invoice.

(b) Any amount to be remitted by the party receiving Services and not remitted on or before the date on which it is due shall thereafter bear interest at rate of 1.5% per month (18% per annum).

3.4 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by FBC

Subject to Section 4.4 , FBC will indemnify, defend and hold harmless FEI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.2 Indemnity by FEI

Subject to Section 4.4, FEI will indemnify, defend and hold harmless FBC and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FBC's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FBC.

4.3 Limitation of Liability of party providing Services

Neither the party providing Services nor any of its directors, officers, employees, agents or contractors will be liable to the other for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which the party receiving Services may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with the provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of the party providing Services.

4.4 Consequential Losses

Each party acknowledges and agrees that notwithstanding anything else in this Agreement, in no event shall a party or any of their officers, directors, employees, shareholders, agents, or representatives be liable to the other party, any of its affiliates, or any other party for any special, indirect, incidental, exemplary, or consequential damages or loss of goodwill whether such liability is based on contract, tort, negligence, strict liability, or otherwise, in any way arising from or relating to this Agreement or the performance or non-performance of the Services, even if the party has been notified of the possibility or likelihood of such damages occurring.

PART 5

REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties of FEI

FEI hereby represents and warrants to FBC as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FEI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FEI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

5.2 Representations and Warranties of FBC

FBC hereby represents and warrants to FEI as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FBC is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FBC has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FBC enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 6

DURATION, TERMINATION AND DEFAULT

6.1 Effective Date and Term

This Agreement will be effective from July 1, 2010 and will end on December 31, 2011, unless earlier terminated pursuant to the provisions hereof. Thereafter this Agreement will automatically be renewed for further one (1) year terms from January 1 to December 31, subject to Section 6.2 below.

6.2 Termination

This Agreement may be terminated by either FEI or FBC in their sole and absolute discretion at any time by giving fourteen (14) days notice after receipt by either FEI or FBC of written notice thereof from the other party. Such termination shall not affect any rights of the parties which have accrued prior to the date of termination and shall not relieve any party from its obligations which have arisen during the term of this Agreement.

6.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, each party will have no further obligations under Part 2 and will promptly deliver to the other any material documents in the possession of each pertaining to the business of the other.

6.4 Compensation of party providing Services on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, each party will pay to the other all amounts owing hereunder (including any amount owing on account of the fees provided for in Part 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Part 3 which are payable to the party providing Services on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 7

ARBITRATION

7.1 Arbitration

Any dispute between FEI and FBC regarding any allegation that FEI or FBC is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 7.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the rules of National Arbitration Rules of the ADR Institute of Canada Inc. from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 7.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 8

MISCELLANEOUS

8.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party shown on the first page of this Agreement. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

8.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

8.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

8.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

8.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

[Intentionally Blank. Signature Page Follows.

8.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective as of the day and year before written.

FORTISBC ENERGY INC.

By: ______________________

Name: Roger Dall'Antonia

Title: Vice President, Finance & CFO

FORTISBC INC.

By: ______________________

Name: Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

Appendix M

DRAFT PROCEDURAL ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT PROCEDURAL ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by the FortisBC Energy Utilities
(comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.)
for Approval of 2012 and 2013 Natural Gas Rates

BEFORE:

(Date)

WHEREAS:

A. On May 4, 2011, the FortisBC Energy Utilities (FEU or the Companies) filed an Application for their combined Revenue Requirements for FortisBC Energy Inc. (FEI), the Fort Nelson Service Area of FEI (Fort Nelson), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Energy (Vancouver Island) Inc. (FEVI), and for approval of interim and permanent natural gas delivery rates effective January 1, 2012 and permanent rates effective January 1, 2013, pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (the Act), with any variance between 2012 interim rates and permanent rates to be refunded to or collected from customers by way of a rate rider following the approval of 2012 permanent rates;

B. FEI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 5.0 percent effective January 1, 2012 and a further 6.4 percent permanent increase effective January 1, 2013 representing an annual average lower mainland residential customer total bill increase of 2.4 percent in 2012 and a further 3.0 percent increase in 2013;

C. FEI further seeks approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes and approval of the cost allocation to Thermal Energy Services (previously referred to as Alternative Energy Services) as set out in the Application;

D. Fort Nelson region, seeks, among other things, approval pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 6.5 percent effective January 1, 2012 and a further 1.6 percent permanent increase effective January 1, 2013, representing an annual average Fort Nelson residential customer total bill increase of 2.3 percent in 2012 and a further 0.6 percent increase in 2013.

Fort Nelson also seeks approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes as set out in the Application;

E. FEW seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 2.2 percent effective January 1, 2012 and a further 11.9 percent permanent increase effective January 1, 2013, representing an annual average residential customer total bill increase of 1.5 percent in 2012 and a further 7.1 percent increase in 2013, and approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes as set out in the Application;

F. FEVI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction, to maintain current natural gas rates for all customers other than those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012. FEVI proposes to utilize the surplus that will exist in the Rate Stabilization Deferral Account (RSDA) to allow for rates to remain unchanged for 2013;

G. FEVI further seeks approval of its schedule of demand and commodity charges, forecast gross O&M expenditures and, pursuant to section 2.10 of the Special Direction, for its forecast cost of service, forecast capital expenditures, and forecast revenue as set out in the Application;

H. The FEU seek, among other things, approvals including allocation of costs for shared services between the Companies; discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts; changes to depreciation rates; and pursuant to section 44.2 of the Act, for Energy Efficiency and Conservation (EEC) expenditures;

I. In addition to the specific requests included in the Application for each of the Companies, the FEU are collectively applying for a Commission determination of the combined utility cost of service for 2013, subject to the Companies obtaining, at a later date, the necessary approvals to amalgamate. In the event that amalgamation proceeds, the combined cost of service will provide the basis for a harmonized rate structure for an amalgamated entity;

J. The FEU propose a Workshop to review the Application be held on Wednesday, May 18, 2011, commencing at 1:00 pm, at the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC;

K. The Companies propose that a Procedural Conference be held on Tuesday, May 24, 2011 at the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC, commencing at 9:00 am;

L. The FEU believe the Application can be addressed efficiently and effectively through a negotiated settlement process, or in the alternative, by a written hearing process, and propose a draft Regulatory Timetable attached as Appendix A for discussion at the Procedural Conference; and;

M. The Commission considers that establishing a Workshop to review the Application and a Procedural Conference to determine the appropriate regulatory process for the review of the Application is warranted.

NOW THEREFORE the Commission orders as follows:

1. The FEU's request pursuant to section 89 of the Act for interim rates as proposed in the Application for 2012 will be addressed in a subsequent order to be issued following the Procedural Conference. The Commission will receive submissions on the proposed interim rates at the Procedural Conference.

2. A Workshop to review the Application will be held on Wednesday, May 18, 2011, commencing at 1:00 pm in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

3. A Procedural Conference regarding the regulatory process for the review of the Application will be held on Tuesday, May 24, 2011, commencing at 9:00 am in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

4. The Procedural Conference will address matters such as:

   a. identification of principle issues arising from or related to the Application;
   b. process options for review of the Application, including;
      - negotiated settlement process
      - written hearing
      - oral public hearing
      - or, as appropriate, some combination of the above
   c. timetable (information requests, responses, intervener evidence, etc.);
   d. interim rates;
   e. location(s) of the proceedings;
   f. other matters that will assist the Commission to efficiently review all aspects of the Application.

   After the Procedural Conference, the Commission will issue a further procedural order and regulatory agenda for the review of the Application.

5. The FEU will publish, as soon as possible, in display-ad format, the Notice attached as Appendix B to this Order, in the Vancouver Sun, the Province, and such other appropriate local news publications as may properly provide adequate notice to customers served in the affected service areas.

6. The Application, together with any supporting materials, will be made available for inspection at the FortisBC Energy Utilities, 16705 Fraser Highway, Surrey, BC, V4N 0E8, and at the British Columbia Utilities Commission, Sixth Floor, 900 Howe Street, Vancouver, B.C., V6Z 2N3 and will also be available on the FortisBC Energy Utilities website at www.fortisbc.com and on the BCUC website at www.bcuc.com.

7. Interveners or Interested Parties should register with the Commission, in writing or electronic submission, by Tuesday, May 17, 2011. Interveners should specifically state the nature of their interest in the Application and identify generally the nature of the issues that they may intend to pursue during the proceeding and the nature and extent of their anticipated involvement in the review process.

DATED at the City of Vancouver, in the Province of British Columbia, this day of <month> 2011.

BY ORDER

Attachments

Application by the FortisBC Energy Utilities
(comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.)
for Approval of 2012 and 2013 Revenue Requirements and Natural Gas Rates

DRAFT

REGULATORY AGENDA AND TIMETABLE

ACTION	DATE (2011)
Procedural Order (Notice of Workshop and Procedural Conference)	Tuesday, May 10
Registration of Interveners and Interested Parties	Tuesday, May 17
Workshop (commencing at 1:00 pm)	Wednesday, May 18
Procedural Conference (Timetable and Process - commencing at 9:00 am)	Tuesday, May 24
Procedural Order	Thursday, May 26
Commission Information Request No. 1 to FEU	Thursday, June 2
Intervener Information Request No. 1 to FEU	Thursday, June 9
FEU Response to Information Requests No. 1	Thursday, June 30
Commission Information Request No. 2 to FEU	Thursday, July 21
Intervener Information Request No. 2 to FEU	Thursday, July 21
FEU Response to Information Requests No. 2	Friday, August 19
Negotiated Settlement Process or Hearing if Required (proposed date range)	Tuesday, September 6 to Friday, September 30
FEU Final Argument Submissions	Friday, October 7
Intervener Final Argument Submissions	Friday, October 21
FEU Reply Argument Submissions	Friday, November 4

Workshop and Procedural Conference Location:
Commission Hearing Room
Twelfth Floor, 1125 Howe Street
Vancouver, BC

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Application by the FortisBC Energy Utilities
(comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.)
for Approval of 2012 and 2013 Revenue Requirements and Natural Gas Rates

NOTICE OF WORKSHOP AND PROCEDURAL CONFERENCE

	WORKSHOP
Date:	Wednesday, May 18, 2011
Time:	1:00 pm
Location:	Commission Hearing Room Twelfth Floor, 1125 Howe Street Vancouver, BC

	PROCEDURAL CONFERENCE
Date:	Tuesday, May 24, 2011
Time:	9:00 am
Location:	Commission Hearing Room Twelfth Floor, 1125 Howe Street Vancouver, BC

THE APPLICATION

On May 4, 2011, the FortisBC Energy Utilities (FEU or the Companies) filed an Application, pursuant to sections 59 to 61 of the *Utilities Commission Act* (the Act), for their combined Revenue Requirements for FortisBC Energy Inc. (FEI), the Fort Nelson Service Area of FEI (Fort Nelson), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Energy (Vancouver Island) Inc. (FEVI), and for approval of interim and permanent natural gas rates effective January 1, 2012 and permanent rates effective January 1, 2013. In addition to the specific requests included in the Application for each of the Companies, the FEU are collectively applying for a Commission determination of the combined utility cost of service for 2013, subject to the Companies seeking and obtaining, at a later date in a future application, the necessary approvals to amalgamate. The combined cost of service will provide the basis for a harmonized rate structure for an amalgamated entity.

Among other things, the FortisBC Energy Utilities seek approval of the following for each of the Companies:

- FEI seeks approval of a natural gas delivery rate increase of 5.0 percent effective January 1, 2012 and a further 6.4 percent permanent increase effective January 1, 2013, representing an annual average lower mainland residential customer total bill increase of 2.4 percent in 2012 and a further 3.0 percent increase in 2013, and approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes and approval of the cost allocation to Thermal Energy Services (previously referred to as Alternative Energy Services) as set out in the Application.
- FEI Fort Nelson seeks approval of a natural gas delivery rate increase of 6.5 percent effective January 1, 2012 and a further 1.6 percent permanent increase effective January 1, 2013, representing an annual

average Fort Nelson residential customer total bill increase of 2.3 percent in 2012 and a further 0.6 percent increase in 2013, and approval of the RSAM rider for applicable rate classes as set out in the Application.

- FEW seeks approval of a natural gas delivery rate increase of 2.2 percent effective January 1, 2012 and a further 11.9 percent permanent increase effective January 1, 2013, representing an annual average residential customer total bill increase of 1.5 percent in 2012 and a further 7.1 percent increase in 2013, and approval of the RSAM rider for applicable rate classes as set out in the Application.
- FEVI seeks approval to maintain current natural gas rates for all customers except those with specified rates in their transportation service agreements, for a two-year period commencing January 1, 2012;
- The FEU seek other approvals including allocation of costs for shared services between the Companies; discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts; changes to depreciation rate; and pursuant to section 44.2 of the Act, for Energy Efficiency and Conservation (EEC) expenditures.

THE REGULATORY PROCESS

British Columbia Utilities Commission (Commission) Order G-xx-11 has established a Workshop, a Procedural Conference and a Preliminary Regulatory Timetable for the regulatory review of the Application.

The detailed Regulatory Timetable can be reviewed on the Commission's website at www.bcuc.com>Current Applications>

FEU will hold a Workshop on Wednesday, May 18, 2011 commencing at 1:00 pm in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, B.C.

The Commission will hold a Procedural Conference regarding the further regulatory process for the review of the Application on Tuesday, May 24, 2011 commencing at 9:00 am in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, B.C.

REGISTERING TO PARTICIPATE

Persons who wish to actively participate in this proceeding should register as Interveners with the Commission in writing by Tuesday, May 17, 2011, and should identify the issues that they intend to pursue as well as the nature and extent of their anticipated involvement in the review process indicating whether they plan to attend either or both the Workshop and/or the Procedural Conference. Interveners will receive email notice of all correspondence and filed documents. An e-mail address should be provided if available.

Persons not expecting to actively participate, but who have an interest in the proceeding, should register as Interested Parties with the Commission in writing, by Tuesday, May 17, 2011 identifying their interest in the Application. Interested Parties will receive an Executive Summary of the Application and a copy of the Commission's Decision when issued.

PUBLIC INSPECTION OF DOCUMENTS

The Application and supporting material will be made available for inspection at the following locations:

FortisBC Energy Utilities	**British Columbia Utilities Commission**
16705 Fraser Highway	Sixth Floor, 900 Howe Street
Surrey, BC V4N 0E8	Vancouver, BC V6Z 2N3

The Application and supporting material are also available for viewing on the following web sites:

http:// www.fortisbc.com   http:// www.bcuc.com

All submissions and/or correspondence received from active participants or the general public relating to the Application will be placed on the public record and posted to the Commission's website.

FURTHER INFORMATION

For further information, please contact Ms. Alanna Gillis, Acting Commission Secretary, as follows:

Telephone:	(604) 660-4700	BC Toll Free:	1-800-663-1385
Fascimile	(604) 660-1102	E-mail:	Commission.Secretary@bcuc.com