IN THE MATTER OF

THE FORTISBC ENERGY UTILITIES

[comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.]

2012-2013 REVENUE REQUIREMENTS AND RATES

DECISION

April 12, 2012

Before:

D.A. Cote, Commissioner/Panel Chair
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

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1.0 EXECUTIVE SUMMARY

On May 4, 2011, the FortisBC Energy Utilities (FEU, Companies, Utilities) consisting of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area , FortisBC Energy (Whistler) Inc. and FortisBC Energy (Vancouver Island) Inc. applied for approval of their 2012 and 2013 Revenue Requirements.

Pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act (UCA)* the Companies sought across-the-board interim and permanent rate increases for each of the FEU with the exception of FEVI where the maintenance of existing rates was sought. This was revised by the FEU with their Evidentiary Update on September 21, 2011, and again for Fort Nelson only at the oral hearing on October 3, 2011. The Companies now seek the following:

- Across-the-board increase of 5.59 percent and 6.29 percent for FEI; 5.02 percent and 6.54 percent for FEW; and 0 percent and 1.32 percent for Fort Nelson effective January 1, 2012 and 2013 respectively. No change to the proposed rates for FEVI was requested.
- A capped amount of $74.5 million for Energy Efficiency and Conservation (EEC) expenditures in each of 2012 and 2013. This was subsequently amended to $64.5 million.

The Application was filed and reviewed during a period of significant and continuing change in terms of BC Government Energy Policy and Regulation with respect to the *Clean Energy Act* and *Demand Side Measures Regulation*. The FEU can also be described as companies that are in transition as they are in the process of exploring and developing an expanded range of service offerings in non traditional areas in addition to the delivery of natural gas to their traditional customer base. Collectively referred to as Alternative Energy Services (AES) within this Proceeding, these new service offerings included a Biomethane service, a natural gas vehicle business and a thermal energy services program.

In reviewing the Application, the Commission Panel identified three overriding issues which we believe have a direct impact on this Proceeding. These issues are as follows:

- The Current Cost of the Natural Gas Commodity and Impact on Rates.

  - the use of cost deferral mechanisms have been examined to ensure they are appropriate, given the current low cost of natural gas.

- The Importance of Productivity Improvements.

  - a question facing the Commission Panel is whether the FEU have fully optimized improved productivity opportunities.

- Importance of Intergenerational Equity.

  - the weight placed on the need to preserve intergenerational equity to the extent possible in this Proceeding.

None of these issues were determinative but they have provided the Panel with a lens through which to examine a number of the issues which have arisen within this Application.

In its review of the Application, the Commission Panel has examined and considered the positions of the various parties with respect to both financial and non-financial areas and the issues related to each. Our review of the issues related to expenses and other concerns included the following areas:

- Sales Forecasting Mechanisms
- Departmental Operations and Maintenance Expenses
- Other Operational Cost Issues and Administrative Matters
- Depreciation, Capitalization and Rate Base Issues
- Energy Efficiency Conservation Expenses and Program Issues

While not approving all of the requests of the FEU made in this Application, the Commission Panel has approved much of what has been applied for. Further, we believe that the resulting rates are just and reasonable as required under sections 59 and 60 of the *UCA* while amongst other things, encouraging the FEU to increase efficiency, reduce costs and enhance performance.

A discussion of some of the highlights and key issues related to the Decision follows:

- **Sales and Forecasting Mechanisms**

Sales volume forecasts are a key input to the rates that the FEU will require over the test period. The Companies utilized a forecast methodology which was consistent with past forecasts which have been approved. Some concerns were raised by Interveners with respect to forecasting estimates. However, on balance, the Commission Panel is satisfied that the level of accuracy was reasonable and approved demand forecasts as filed for all customer groups.

- **Departmental Operations and Maintenance Expenses**

The FEU have applied for $261.1 million in Operations and Maintenance (O&M) expenditures in 2012 and a further increase in 2013. A major consideration for the Commission Panel is whether in this Application, the FEU have demonstrated that they have optimized productivity levels. After consideration of the evidence, the Panel is not persuaded that the Companies have done all they can to optimize productivity and manage cost levels down. The Commission Panel has directed the FEU to reduce their O&M expenditures by $4 million in 2012 and 2013.

Additionally, the Panel made further determinations with regard to new expenditure requests. These resulted in Departmental O&M reductions in Operations, Supply and Resource Development, Energy Solutions and External Relations and Information Technology.

- **Other Operational Cost Issues and Administrative Matters**

The Commission Panel finds that there were benefits to the shareholder that accrue from the FEU's community involvement spending. The Panel has directed that all community spending be allocated on a 50/50 basis between the ratepayer and the shareholder. The Olympic Cauldron was an issue which received significant attention within the Proceeding. The Commission Panel finds that the Cauldron was not a distribution asset providing service to ratepayers and the FEU were directed to remove it from rate base. Further, the Panel finds that the shareholder received a benefit from funding the Cauldron and approves a 50/50 sharing of the cost between ratepayer and shareholder.

Another key issue within this Proceeding was the Calculation of Costs for Thermal Energy Services. The Commission Panel is of the view that the allocation of sales and marketing costs to TES is insufficient and finds that a more reasonable allocation of overhead and sales and marketing cost is $750 thousand for each year of the test period. In addition, the Panel has made determinations with respect to FEI Southern Crossing Third Party Revenues, use of the Uniform System of Accounts and reconnection/reactivation charges.

- **Depreciation, Capitalization and Rate Base Issues**

The Commission Panel accepts the Gannett Fleming Depreciation Study and depreciation rates as recommended by that study and accepts the FEU's proposal to use the traditional method of including negative salvage in rates during the test period. The Panel has also approved recovery of the Asset Losses outlined in the Application.

Concerning capital expenditures, the Commission Panel approves the forecast for growth capital expenditures for Mains, Services and Meters as well as Facilities and Equipment capital expenditures and IT capital expenditures. Additionally, the Panel has approved the inclusion of a second LNG Tanker in rate base and but finds that the Mobile Refuelling Unit was not an asset that should be for the account of the ratepayer and has directed the FEU to remove the cost from rate base.

- **Energy Efficiency Conservation Expenses and Program Issues**

The FEU have requested EEC expenditures of $64.5 million for 2012 and 2013 as well as approval of a new financial handling of EEC deferral accounts and made a series of requests related to the framework for EEC, among other things. The Commission Panel has approved expenditures of $29.707 million in 2012 and $36.204 in 2013 for programs in two broad categories; Existing Program Areas and New Program Areas. Additionally, the Panel has approved the FEU's proposal for EEC deferral account handling and made determinations on matters related to the EEC Framework and other issues arising from the Application.

2.0 INTRODUCTION

2.1 The Application and Approvals Sought

This Application has been filed by the FEU consisting 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) for approval of their 2012 and 2013 Revenue Requirements.

The FEU sell and deliver natural gas to residential, commercial and industrial customers throughout British Columbia (BC). They provide service to over 940,000 customers which are over 95 percent of gas users in the Province. Their operations are subject to regulation by the British Columbia Utilities Commission (Commission, BCUC). In addition to providing natural gas through traditional pipelines to customers, the Companies have recently expanded their scope and entered new businesses collectively referred to as Alternative Energy Solutions Services (AES) that have been proposed as regulated services. The entry of the FEU into these new business areas is the subject of the Alternative Energy Solutions Inquiry initiated by the Commission and running coincidentally with this hearing process.

Pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (*UCA*) RSBC 1996 c. 473 the Applicants, among other things, sought the following:

- Across-the-board interim and permanent rate increases of 5.04 percent and 6.36 percent for FEI, 6.51 percent and 1.64 percent for Fort Nelson and 2.23 percent and 11.90 percent for FEW effective January 1, 2012 and 2013, respectively;
- Maintenance of 2011 rates for 2012 and 2013 for all customers other than those with specified rates in their transportation agreements for FEVI.

This was subsequently revised by the FEU with their September 21, 2011, Evidentiary Update (Exhibit B-21) and again for Fort Nelson only at the Oral Hearing on October 3, 2011. (T2: 274)

The Companies now seek the following:

- Across-the-board increases of 5.59 percent and 6.29 percent for FEI; 5.02 percent and 6.54 percent for FEW; and 0 percent and 1.32 percent for Fort Nelson effective January 1, 2012 and 2013, respectively. No change to the proposed rates for FEVI was requested;
- A capped amount of $74.5 million for EEC expenditures in each of 2012 and 2013. This was subsequently amended to $64.5 million.

A Full listing of the original approvals sought can be found in Section 8 of the Application. (Exhibit B-1, pp. 768-776) Also, a complete listing of the Commission Panel's directives is attached as Appendix A to this Decision.

2.2 Regulatory Process

The Regulatory process included one Procedural Conference, three rounds of Information Requests (IRs), an oral hearing, Final Submissions from the FEU and the Interveners and Reply Submissions from the FEU. Details of the Regulatory Process are outlined in Appendix B to this Decision.

Eight organizations registered as Interveners in this Proceeding. They are listed in Appendix C to this Decision.

2.3 Procedural Background

FEI, the largest of the FEU, is coming off a period where revenue requirements were determined by either Performance Based Rates (PBR) or Negotiated Settlement Processes. The last time a revenue requirements for FEI was determined by an Oral Hearing Process was in 2003 when FEI was known as B.C. Gas Utility Limited. The length of time since an Oral Hearing Process was used to decide a revenue requirements application of FEU was a consideration in the Commission Panel determining the process for the current Proceeding. A summary of the procedural background for this Application follows.

On May 4, 2011, the FEU filed their 2012 and 2013 Revenue Requirements Application (Application) pursuant to sections 59 to 61 and 89 of the *UCA*. An amendment to the Application was filed on May 16, 2011.

By Order G-81-11 dated May 6, 2011, the Commission established an interim regulatory timetable which, among other things, included a procedural conference scheduled for June 15, 2011. The date for this Procedural Conference was subsequently moved to July 7, 2011 by letter L-45-11 dated May 26, 2011.

On July 20, 2011, following the Procedural Conference, the Commission issued Order G-129-11 which established an Oral Hearing Process to review the Application commencing October 3, 2011. This was preceded by a second round of IRs and additional process concerning the filing and review of Intervener evidence. In addition to matters related to process, the Procedural Conference dealt with issues related to confidential filings, capital structure, interim rates and the potential conflict arising from the timing of this Proceeding and the AES Inquiry which was being conducted coincidentally.

The most contentious issue was related to the timing of this Hearing and the AES Inquiry. The Energy Services Association of Canada (ESAC) and Corix Utilities Inc. (Corix) raised concerns that any funding and cost allocations resulting from this Proceeding may precede the Commission's determinations of principles governing AES initiatives. They submitted that the conflict could be avoided by proceeding first with the AES Inquiry ahead of this Application or, in the alternative, proceeding with the hearing of the two applications in parallel. (T1: 24-28) The Commission Panel, while acknowledging the importance of the concerns raised by Corix and ESAC, stated that the process would be best served by moving ahead with this Application in a timely fashion. In addition, the Commission Panel noted that the Panel for the AES Inquiry had addressed the issue of the impact of the AES Inquiry on other proceedings in its Reasons for Decision issued with Order

G-118-11.[1] In its Reasons for Decision, that Panel stated that the intent of the AES Inquiry was for it to be applied in a forward looking manner with no direct impact on past or current proceedings. As a consequence, the Panel in this Proceeding was not persuaded there was a need to delay this Application. (Exhibit A-7, pp. 5-6)

On August 30, 2011, pursuant to section 99 of the *UCA*, the Companies filed a request for variance to the regulatory process the Commission had established (Variance Request). Specifically, the Companies proposed to amend a number of approvals sought in the Application in support of proceeding with a negotiated settlement process (NSP) with certain items either withdrawn or excluded based on a change of circumstance. The excluded items were three policy-related subject matter areas related to EEC and certain accounting treatments. The FEU further proposed that these matters along with any other unresolved issues from the NSP would be addressed at a hearing process following the NSP. In support of the Variance Request, the FEU reported that the intervening groups representing customers were in agreement. (Exhibit B-19) Subsequent to the Variance Request, two Interveners representing commercial interests, ESAC and Corix, filed response letters which conditionally supported the proposed NSP. (Exhibit C-5-3, Exhibit C-6-3) On September 14, 2011, the Commission issued Order G-158-11 with Reasons for Decision denying the Variance Request.

In response to the B.C. Sustainable Energy Association and Sierra Club (BCSEA) filing of written testimony from Mr. John Plunkett of the Green Energy Economics Group, Inc. on August 23, 2011, the FEU filed their EEC Plan as Rebuttal Evidence on September 26, 2011, noting the Regulatory Timetable did not address the potential need for the Companies to file this evidence. The FEU requested the Commission accept the Rebuttal Evidence in the interests of fairness and ensuring the Commission has access to a complete evidentiary record. (Exhibit B-25, cover page)

On September 29, 2011, the Commission issued a letter to all participants proposing a series of

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[1] In the Matter of An Inquiry into FortisBC Energy Inc.'s Offering of Products and Services in Alternative Energy Solutions and other New Initiatives; Order G-118-11, July 8, 2011 (AES Inquiry)

amendments to the Regulatory Timetable to address concerns which had been raised by Commission Staff with respect to the filing of FEU's Rebuttal Evidence. (Exhibit A-15) The Commission's proposal called for Panel three to be split and separated into two panels: (1) an Energy Solutions Panel and (2) an EEC Panel. The Energy Solutions Panel would be heard in accordance with the existing timetable, while the EEC Panel would be heard the week beginning November 14, 2011, which would allow for one round of IRs on the Rebuttal Evidence. In addition, the Commission letter requested participants to be prepared to make submissions on the interim rates which had been requested by the FEU in their letter of September 26, 2011. (Exhibit B-24) The letter also included a request for submissions on the FEU's request for EEC funding of $5 million for existing programs to cover the period January 1, 2012 to the time of the Commission's final decision. These matters were to be dealt with prior to the hearing of evidence at the Oral Hearing scheduled for October 3, 2011.

After dispensing with the matters related to splitting the hearing into two time periods, the Oral Hearing began on October 3, 2011, as scheduled and continued through Tuesday, October 11, 2011. There were four witness panels: (1) Policy Panel, (2) Finance, Rates and Energy Supply Panel, (3) Energy Solutions Panel and (4) Operations Panel.

On October 20, 2011, the Commission issued Order G-177-11 granting the Companies interim approval of requested rates and EEC funding in the amount of $5 million.

Following a round of IRs, the EEC Panel testified commencing November 14, 2011 and continuing through November 15, 2011 whereupon the Oral Hearing was adjourned. Written Final Submissions were filed by FEU on December 2, 2011, supplemented by the FEU's filing on the amendments to the *Demand-Side Measures Regulations* on December 16, 2011, followed the filings of Intervener Submissions on December 23, 2011 through to January 6, 2012. Reply Submissions were filed by FEU on January 25, 2012.

2.4 Approach to this Application

In the view of the Commission Panel, there are a significant number of issues at play in this Application. To deal with these we will begin in Section 3 by setting out the context for the Application discussing the Applicants in terms of their movement toward and becoming what they refer to as an "Integrated Energy Service Provider," the potential impact of this on the ratepayer and the impact of Government Policy and the *Clean Energy Act (CEA)* SBC 2010, c. 22. We will then examine in Section 4 what the Panel believes to be overriding issues which have a direct impact on this Application. These include the importance of productivity improvements and intergenerational equity in rate setting as well as the impact on rates of the current cost of the natural gas commodity. While these issues will not be determinative in and of themselves, they will provide a lens through which to examine various issues as they arise. Following this we will examine the Application in some detail beginning in Section 5 with Sales Volume Forecasts, continuing in Sections 6 and 7 with an examination of Operations and Maintenance Expenses as well as other Administrative Matters and concluding with a review of Energy Efficiency and Conservation.

3.0 REGULATORY CONTEXT

3.1 Introduction

This Application is being reviewed during a period of significant change in terms of BC Government Energy Policy and regulation. The *CEA* which was introduced in 2010 was further amended in June of 2011. More recently, the *Demand-Side Measures Regulation* issued under the *UCA* on November 6, 2008, was amended on December 8, 2011. Add to this the Provincial Government's announcement on February 3, 2011, of changes to the BC Government's "The BC Energy Plan: *A Vision for Clean Energy Leadership"* (2007 Energy Plan) and it becomes clear that we are in a period of re-examination and considerable change. It can also be stated that this Application and its review is occurring during a period of major change for the FEU. As noted previously, the FEU have embarked upon a series of new business initiatives which have the potential to transform the positioning of the Companies and how they do business in the future.

Given the level of change in both the policy environment and the approach to new business initiatives being undertaken by the FEU, the Commission Panel believes there is value in examining both of these areas to set a context for this Application.

3.2 FortisBC Energy Utilities an Organization in Transition

The FEU can be described as a group of companies in transition. While still highly reliant upon the delivery of natural gas to residential, commercial and industrial customers as their primary business, the FEU have made significant progress in moving away from their traditional roots. In recent years, the Companies have explored and developed what they believe to be an expanded range of service offerings to satisfy growing needs of the customer base. As a result, the Companies have initiated programs into non-traditional areas including a Biomethane offering, a program designed to grow specific segments of the natural gas vehicle (NGV) business and a

Thermal Energy Services (TES) program. Collectively, these will be referred to as AES Initiatives within this Decision.

The genesis for much of this change in approach may well have been driven by the same concerns as those raised in the Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas Whistler Inc. (collectively, Terasen Companies) Return on Equity and Capital Structure Proceeding from 2009 (2009 ROE Proceeding). In the 2009 ROE Proceeding, the Terasen Companies raised a number of factors which they argued were contributing to increased business risk. (Exhibit B-1, p. 24, Tab 1) In the view of the Terasen Companies, these factors, which included items such as the impact of Provincial climate change and energy policies and the growth of electricity as the fuel of choice for high-density housing, had the potential to significantly affect the ability of the Terasen Companies to earn a return on capital. The Commission Panel in the 2009 ROE Decision agreed with the Terasen Companies with respect to climate change and energy policies noting "that the introduction of climate change legislation by the Provincial Government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity."[2] (2009 ROE Decision, p. 37)

Of importance is that the concerns of the Companies were a factor in their decision to explore alternative business initiatives more closely aligned with British Columbia's climate and energy policies. On June 8, 2010, Terasen Gas Inc. filed an application for approval of what it described as an end-to-end business model encompassing the purchase of Biomethane for sale to its customers. This application was filed against the backdrop of the *Clean Energy Act* which received Royal Assent on June 3, 2010 and, in Terasen's view, underlined the importance of its role in developing renewable resources, reducing GHG emissions and reducing waste by using biogas and biomass as

[2] In the Matter of An Application by Terasen Gas Inc. (TGI), Terasen Gas (Vancouver Island) Inc. (TGVI) and Terasen Gas (Whistler) Inc. (TGW) (collectively the Terasen Utilities) for Return on Equity and Capital Structure; Decision and Order G-158-09 dated December 16, 2009 (2009 ROE Decision)

a means of promoting energy efficiency.[3]

This was followed on July 15, 2010, with the Terasen Companies' filing of their 2010 Long Term Resource Plan Application. In addition to providing a high level examination of future demand and supply source expectations and required actions, that application provided insight into potential low and no-carbon initiatives and the scope and magnitude of future EEC measures. Within its Decision on the 2010 LTRP, the Commission Panel echoed the view of many of the Interveners in the proceeding regarding the new business initiatives and their related business models. The Panel in the 2010 LTRP Decision noted that if the new initiatives were allowed to evolve on an *ad hoc* basis as proposed by the Terasen Companies, an opportunity for a comprehensive and systematic consideration of the regulatory issues arising as a result of these new initiatives would be lost. Key issues raised by the Panel in the 2010 LTRP Decision included the following:

- Business risk, risk premiums, stranded assets, "who pays for what" and whether EEC funding should be applied;
- Concern that there may be a risk of unfair advantage for Terasen which could adversely impact the creation of competitive enterprises;
- Whether the public interest is served by placing the costs related to these new initiatives on the traditional natural gas ratepayer;
- The application of British Columbia enacted legislation designed to promote carbon and GHG reduction with respect to the "who pays" question.

The Commission Panel concluded its discussion by stating its belief that "the changes being contemplated and the issues arising from them are significant enough to warrant a formal process to address them at a future date in the not too distant future."[4] (2010 LTRP Decision, pp. 27-28) This led to the AES Inquiry which began a few months after the 2010 LTRP Decision was rendered. In December, 2010, Fortis Energy Inc. (FEI) made application to the BCUC to approve "General

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[3] In the Matter of An Application by Terasen Gas Inc. for Approval of a Biomethane Service Offering and Supporting Business Model and for the Approval of the Salmon Arm Biomethane Project and for the Approval of the Catalyst Biomethane Project; Decision and Order G-194-10 dated December 14, 2010 (Biomethane Decision)

[4] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. 2010 Long Term Resource Plan; Decision and Order G-14-11 dated February 1, 2011 (2010 LTRP Decision)

Terms and Conditions" to allow it to offer a fuelling service for Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) to potential customers with fleets of buses, heavy duty and vocational trucks which utilize a return to base method for refuelling. In the application, FEI proposed to build a new CNG/LNG customer base. In the CNG/LNG Decision,[5] the Commission Panel found that, while benefits would accrue to FEI's new NGV customers as well as to residents of British Columbia generally, there were significant risks with the venture being proposed. Primary among these was the level of certainty with respect to the future price spread between natural gas and conventional fuels as well as the apparent need for ongoing subsidization of the cost of conversion to natural gas engines through incentives. The Panel also pointed out that there were no natural monopoly characteristics implicit in a CNG/LNG infrastructure and, if the services were provided by an organization that was not already a public utility, it would not be subject to regulation. The Panel further found that because of the risks involved and the potential for unregulated competition in this market, the subsidization of the NGV fuelling facilities by FEI's existing ratepayers would be neither just nor fair nor in the public interest. Consequentially, the proposed General Terms and Conditions were rejected as being too general and failing to provide assurance that the actual cost of service would be recovered from the customer as fully as possible. This ruling was significant in that it addressed the "who pays" issue and acknowledged that this business venture could well have competitors and these would potentially be non-regulated participants. Moreover, while not addressing the appropriateness of a cost of service model for such undertakings, the Decision did speak to the need to carefully separate costs related to the new initiative from the day to day cost of running a utility.

3.3 Government Policy/*Clean Energy Act*

The business environment for the FEU is one where government policy plays an increasingly significant role.

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[5] In the Matter of An Application by FortisBC Energy Inc. for Approval of a Service Agreement for Compressed Natural Gas Service with Waste Management of Canada Corporation and General Terms and Conditions for Compressed Natural Gas and Liquefied Natural Gas Service; Decision and Order G-128-11 dated July 19, 2011 (CNG/LNG Decision)

The 2007 Energy Plan built on the BC Government's Energy Plan of 2002 and presented a broad strategy for the Province and all British Columbians to reduce greenhouse gas emissions and for the Province to become energy self-sufficient. Building on this, the provincial government, among other things, enacted legislation, made regulations, and established various programs to combat climate change and steer the Province in a new, "green" direction.

The *Greenhouse Gas Reduction Targets Act* SBC 2007, c. 42 was passed. This legislation, among other things, established targets for the reduction of greenhouse gas emissions in BC.

A carbon tax was imposed pursuant to the *Carbon Tax Act* SBC 2008, c. 40, which received Royal Assent on May 29, 2008. This tax became effective on July 1, 2008, has increased by $5.00 per tonne of CO2 equivalent emissions each year since then, and is currently set at $25 per tonne of CO2 equivalent emissions. It will increase to $30 per tonne on July 1, 2012. As described by the BC Ministry of Finance on its website:

> A carbon tax is usually defined as a tax based on greenhouse gas emissions (GHG) generated from burning fossil fuels. It puts a price on each tonne of GHG emitted, sending a price signal that will, over time, elicit a powerful market response across the entire economy, resulting in reduced emissions."

Natural gas, as a carbon-emitting fuel source, is subject to the Carbon Tax.

Numerous regulations were enacted, including the *Demand-Side Measures Regulation*, BC Reg. 326/2008, in furtherance of government policy. The *Demand-Side Measures Regulation* was made in late 2008 pursuant to authority provided by s. 125.1 of the *Utilities Commission Act*.

The *Clean Energy Act* came into force on June 3, 2010. As a result of the enactment of the *CEA*, consequential changes were made to a number of existing statutes, including the *Utilities Commission Act*.

The *Clean Energy Act*, among other things, defines "British Columbia's energy objectives," which objectives replaced the "government's energy objectives" previously found in the *Utilities Commission Act*. These objectives are set out in s. 2 of the *Clean Energy Act*. Applicable objectives are required to be considered by the Commission in a number of instances, including when the Commission is considering whether to accept a long-term resource plan filed by a public utility pursuant to s. 44.1 of the *Utilities Commission Act*, or an expenditure schedule filed by a public utility pursuant to s. 44.2 of that *Act*.

The *Demand-Side Measures Regulation* initially applied only to demand-side measures proposed by British Columbia Hydro and Power Authority (BC Hydro), but as of June 1, 2009, applied to other public utilities, including the FEU.

More recently, in December 2011, the provincial government amended the *Demand-Side Measures Regulation* to, among other things, basically modify the application of the total resource cost test for cost effectiveness to:

(i) Set the avoided cost of natural gas for a demand-side measure as avoided capacity cost plus one half of BC Hydro's long run marginal cost for electricity from clean or renewable resources (as defined in the *Clean Energy Act*), and

(ii) Increase the benefits attributed to a demand-side measure/demand-side measure portfolio (other than a demand-side measure for residents of low-income households) by a minimum of 15%, subject to certain exceptions. Demand-side measures which are not cost effective without the additional 15% adder may not make up more than 33% of an expenditure portfolio.

The FEU have filed an expenditure schedule pursuant to s. 44.2 for their "demand-side measures."

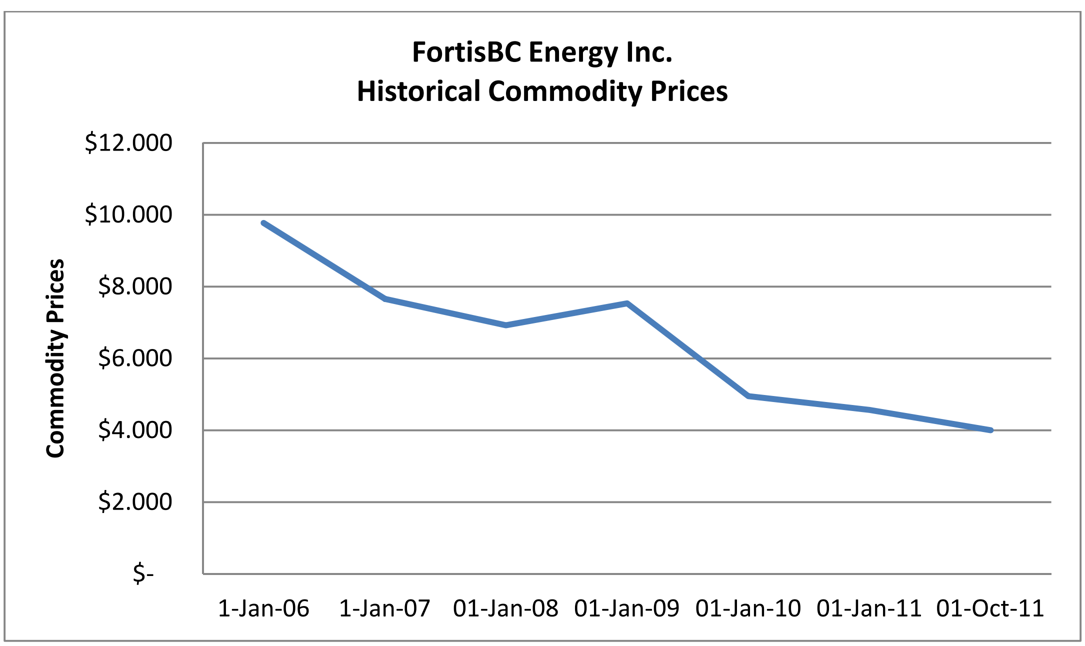
4.0 OVERRIDING ISSUES

4.1 Cost of Commodity and Impact on Rates

The primary purpose of this Proceeding is to review and approve the revenue requirements and resultant rates for the next two-year test period. A decision in this Proceeding will result in the determination of a delivery rate to be charged to the customer which is only one of three components which make up the per gigajoule cost paid. The other two components are the midstream and commodity charges. In addition, there is a basic charge which is a constant per day charge. Of the four components making up a natural gas bill, the most significant amount has traditionally been the commodity charge or the charge for natural gas.

The price of the natural gas commodity component has dropped significantly in recent years. This is outlined in Table 1.1 which shows graphically the range of the natural gas commodity charge for residential customers annually for the period beginning January 1, 2006 through October 1, 2011.

Table 1.1



(Source: Exhibit B-9, BCUC IR 1.156.1, Order G-156-11)

The commodity cost charged by FEI for natural gas on January 1, 2006 was $9.77. The commodity cost charged by FEI for natural gas which took effect on October 1, 2011 is $4.01. This represents a decrease in the price of the natural gas commodity of 58.9 percent over a six-year period. The sharp reduction in natural gas commodity prices over the past few years is directly related to the development of previously untapped shale gas reserves which has significantly reduced commodity market prices in North America. Further, there is nothing to suggest that these low commodity prices will not continue into the future for at least the short term. (Exhibit B-9, BCUC IR 1.156.1, Order G-156-11)

It is clear from the information presented that, with respect to commodity rates and the overall per gigajoule price of delivered gas, many British Columbians are enjoying the benefit of the most favourable rates in some time. Because of this, the Commission Panel has given consideration to whether this is a time when certain costs which might be proposed to be deferred to the future should be taken into current operational costs. This matter was addressed by Counsel for the Commission in the Oral Hearing.

After confirming that the price of natural gas is low Mr. Walker, President and CEO of the FEU was asked whether ratepayers would be better off to pay down some deferral costs in the present as approved to allowing them to grow and accumulate carrying changes given these low costs. Mr. Walker responded:

> "In principle I believe that the more you can pay and not have deferral accounts and keep things in real time as a principle is something I would agree with. I'd like to better understand the specifics if it was possible for me to be more - - to talk about it more." (T2: 232)

Mr. Walker's response was understandably not definitive because to this point Commission Counsel had provided no specific example as to where this principle could be applied. The Commission Panel understands this but nonetheless interprets Mr. Walker's comments to indicate that at least in a general sense, the principle of keeping costs in real time as opposed to deferring them to the future is something he would agree with. The Panel is of a similar view. Many customers are currently enjoying favourable rates and, in the view of the Panel, would not be well served by unnecessarily deferring costs from the current test period to a later time when natural gas prices may be less favourable. Accordingly, in our review of this Application, the Commission Panel will examine the use of cost deferral mechanisms to determine whether they are appropriate for both present and future circumstances.

4.2 Importance of Productivity Improvements

The need for continued productivity improvements is very much an underlying issue in this Proceeding. The Commercial Energy Consumers Association of BC (CEC) in both the Oral Hearing and in Final Submissions expressed its concern with whether the Companies had placed sufficient emphasis on this area. The Commission Panel places significant weight on the importance of this issue given the success which was achieved by the FEU during the PBR period which ended in 2009.

Mr. Walker, FEU President and CEO, addressed the subject of productivity in his testimony in the Oral Hearing by underlining the Companies' commitment to such a focus in moving their business forward. In support of this, he stated that to be sustainable, a company must find a way to deliver service without just driving incremental cost. (T2: 190)

CEC's position is that while the FEU are doing numerous things well, an area deserving a great deal of attention in this test period is that of productivity improvements. CEC points out that the commercial customer group is facing increasing pressure on costs resulting in members placing greater focus on austerity measures. Further, the CEC urges the Commission to direct the FEU "to direct their focus on finding efficiencies and productivity improvements for the benefit of ratepayers." (CEC Final Submission, pp. 4-5)

The British Columbia Old Age Pensioners' Organization *et al* (BCOAPO), while not addressing productivity improvements specifically, does submit that the gap between the cumulative effective delivery rate increase and the cumulative increase in the CPI widens going forward which it argues is evidence of the lack of sustainable productivity improvements which resulted from the PBR period ending in 2009. (BCOAPO Final Submission, p. 12)

The FEU submit that the evidence on the record supports the position that the Companies have forecasted costs which are fair and reasonable to provide customers with safe and reliable service. Further, the FEU present a number of examples of productivity improvements which they believe are representative of their approach to find ways to reduce costs. (FEU Reply, pp. 1-2)

The Commission Panel at this time does not take issue with any of the statements made by the parties and is in agreement with all that an important issue in every revenue requirements hearing is the management of productivity. In keeping with this, we would like to examine the issue of productivity improvement initially at a higher level, examining first the issue of productivity in a monopolistic world and then discussing the role performance based rate making has had in stimulating productivity improvements. The Panel is of the view that this examination will provide a context in which this Application can be reviewed.

In a non-regulated competitive business environment, competition within industry segments is considered to provide an effective incentive for individual businesses to find productivity improvements in their operations. In this environment, and all other things being equal, a business offering a product or service to customers at the lowest cost generally results in maximized sales and profits for that business. In a regulated business monopoly, the incentive to drive productivity improvements is very different. In a monopoly, there is less incentive to keep costs down and/or deliver more efficient service as customers do not have an alternative service provider. In this type of business environment, the price of a product or service is generally not determined by a need to compete with alternative offerings. The difference between a monopoly and a competitive environment serves to underline the challenge facing regulated monopolies in driving productivity improvement when there is less motivation to do so.

In making a decision on rates and revenue requirements, a key consideration of the regulator is the extent to which the regulated utility has sought and taken advantage of opportunities to improve its level of productivity. As outlined in section 59 of the *UCA,* the Commission must determine if rates requested within an application are just and reasonable within the meaning of section 59. In setting rates under the *UCA*, subsection 60(1)(b) requires the Commission to have due regard to setting a rate that

(i) is not unjust or unreasonable within the meaning of section 59,
(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and
(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance.

Section 59(5) provides that a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for services of the nature and quality provided by the utility,
(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
(c) unjust and unreasonable for any other reason.

Therefore, in determining rates under section 59 of the *UCA,* the Commission Panel must determine if the evidence in this Proceeding indicates that rates requested by the FEU are just and reasonable as outlined in section 59 while, amongst other matters, having due regard to encouraging the FEU to increase efficiency, reduce costs and enhance performance.

One method of incenting regulated monopolies to achieve productivity improvements has been to use performance based regulation (PBR). When PBR is combined with a Negotiated Settlement Process the ratepayers and the utility may agree on a level of costs and certain cash outflows, often with a formula-based approach. Typically, the forecasting of expected costs will include escalators for customer growth and inflation and also, a cost reducer for an agreed upon level of productivity improvement. If the utility is able to achieve actual costs that are lower than the targeted results and do so without compromising safety and reliability, the additional cost savings are shared between the ratepayers and the shareholder. The program is therefore designed to motivate the utility to invest significant effort in identifying additional productivity improvements in order to allow the shareholder to realize earnings over and above the approved return on equity. In British Columbia, PBR, combined with the Negotiated Settlement Process has played a role within the rate setting process of FEI. Starting in 2004 and lasting through 2009 FEI operated in a PBR environment. During this period FEI was very successful as targets were met and the Companies note that shared earnings benefits flowing to customers and shareholders totalled $67.5 million each over the six years. (FEU Reply, p. 11)

The Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements. We also recognize that there are drawbacks to the PBR methodology, but acknowledge that the pros and cons of PBR are not at issue at this time. However, the need for improved productivity is very much at issue. The question which must be answered within this Decision is whether FEU has fully optimized improved productivity opportunities and whether the evidence presented supports FEU's position that they have forecasted costs which provide customers with safe and reliable service at rates that are fair and reasonable.

4.3 Importance of Intergenerational Equity

One principle of utility rate design and cost allocation is to ensure intergenerational equity to the extent practicable. The goal is to have the appropriate share of costs that are incurred to provide services to ratepayers in a particular time period recovered from the ratepayers benefiting from the services in that same time period. The FEU use several methodologies to achieve this goal.

Long lived assets that provide benefits to ratepayers over an extended period of time are amortized in a manner that allocates the costs over the life of the assets, rather than allocating all of the costs to the ratepayer at the time the investment is incurred. This allocation is achieved through depreciating the asset, or group of assets, over the life of the asset or asset class, and charging the depreciation expense to the ratepayers who "consume" the asset during a particular time period.

Adherence to the principle of intergenerational equity provides challenges with respect to accurately determining appropriate periods over which to amortize costs. However, the Commission Panel believes that putting in place measures to ensure costs are borne by those who benefit is far more appropriate than ignoring such costs and passing them on to a future generation of customers well after any benefits have been realized. While there may be a temptation to defer costs to a future time period as a means of achieving lower rates, the view of the Panel is that where practical, both the cost and the benefits of a particular undertaking should be balanced over the same period.

In accordance with this, the Commission Panel has placed weight on the need to preserve intergenerational equity to the extent practicable in this Proceeding.

5.0 SALES VOLUME FORECASTS

5.1 Background and Methodology

The FEU sales volume forecasts are a key input to the calculation of the rates that FEU will require for the 2012 and 2013 test period. To prepare their forecasts the FEU first estimated the revenue they would receive using existing rates. This is done for residential and commercial customers by multiplying the projected number of accounts by the normalized use per customer. For Industrial customers, the demand is estimated through a survey. The forecast is then compared to historical normalized data. Forecasts are prepared for each of the Companies' service areas – Mainland, Vancouver Island, Whistler and Fort Nelson. (Exhibit B-1, p. 80)

5.2 Rate Stabilization Adjustment Mechanism

The Rate Stabilization Adjustment Mechanism (RSAM) stabilizes the delivery margin received from residential and commercial customer classes on a use per customer (UPC) basis. If customer use rates vary from the forecast levels used to set the rates, whether due to weather variance or other causes, the utility records the delivery charge differences in the RSAM deferral account. The FEU then provide a refund or a surcharge to customers through a rate rider over the ensuing three years. Having an RSAM mechanism does not offer protection against forecasting errors due to variances between recorded and forecast numbers of customers nor does it mitigate any forecasting risks associated with the non-RSAM customer classes such as Industrial customers. The major variable impacting the UPC which is captured by the RSAM is weather related demand. (Exhibit B-1, p. 92) This mechanism is used for FEI, FEW and Fort Nelson.

In the 2010-2011 RRA, FEVI received approval for an interim rate mitigation strategy to offset the rate pressure resulting from the loss of 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 a Rate Stabilization Deferral Account (RSDA), to capture the differences in 2010 and 2011 between the net revenues received and the actual cost of service, excluding Operations and Maintenance (O&M) variances from forecast. The RSDA captures the volume variance due to the Vancouver Island's forecast versus actual volumes and is similar to the RSAM in this respect. (Exhibit B-1, p. 105)

5.3 Residential Customer Usage Rates and Demand Forecast

The forecast residential energy demand is the product of the residential accounts (including account additions) and the normalized forecast residential UPC rate. This is then compared with historical normalized data. Through this comparison the forecast for gas usage by FEU customers is verified. (Exhibit B-1, p. 80)

Individual average UPC forecasts are developed by the FEU for each service area and for each residential class. Given the large impact weather can have on gas usage, the UPC forecasts are based on "normalized" or average weather conditions using weather data from the past ten years. The FEU's analysis of historic normalized residential use rates indicates a continued downward trend. Residential customer additions and the existing residential customer totals are the second key input in the FEU's residential demand forecast. The customer count (including additions) is multiplied by the average use per customer to form the residential demand forecast.

The FEU housing market forecast is derived from forecasts by Canada Mortgage and Housing Corporation (CMHC) and the Conference Board of Canada (CBOC) and adjusted by FEU staff based on the FEU's view of the local housing market. (Exhibit B-6, BCOAPO IR 1.16.2)

The FEU developed separate single and multi family dwelling forecasts for this Application. These two forecasts are based on the FEU's own internal customer mix, by dwelling, as well as the CMHC and the CBOC forecasts for growth in these two housing sectors. The FEU assert that, as with any forecast, variances from forecast customer additions do occur. The Companies argue that these are attributable to a number of factors including: the recession, the timing lag between housing starts and their new customers, and existing customer turnover. In FEU's view, variances from the short-term forecast customer additions over the test period are not material to the revenue requirement because the variance in the number of new customers is small. (T5: 736) The FEU further argue that this variance in revenues associated with customer additions is partly offset by the variance in the O&M and capital costs associated with those customer additions. (FEU Final Submission, p. 31)

CEC contends that, based on the evidence provided, the FEU may be underestimating the customer additions that are occurring given that the data show that capture rates (the percentage of new housing starts that use natural gas) have varied from just over 30 percent to 40 percent over the last decade. The capture rate projected for 2012 (31.0 percent) and 2013 (30.7 percent) are the two lowest since 2001. CEC also argues that the evidence could be seen as suggesting that the decline in the UPC is flattening out and the use of a higher UPC is warranted. While the CEC recognizes that the RSAM will capture any variances in UPC, it believes it is preferable to use the best estimate for UPC which it argues is higher than the UPC utilized by FEU. (CEC Final Submission, pp. 21-22)

The BCOAPO requests that the FEU be required to file a financial analysis at the time of their next revenue requirements hearing setting out the impact of variances in the forecast of customer additions on all rate classes. (BCOAPO Final Submission, pp. 13-14)

Commission Determination

The Commission Panel recognizes that the residential energy demand forecast put forward by the FEU uses a methodology that is consistent with past forecasts that have been approved by the Commission. Further, the Panel agrees with CEC that the capture rate for new housing additions appears low in historical terms. **However, given the inherent uncertainties in the forecasting process, the RSAM which captures variances in UPC, and the small impact errors in the forecast of account additions would have, the Panel finds the residential demand forecast put forward by the FEU is acceptable. Accordingly, the Commission Panel approves the residential demand**

forecast as filed for use in calculating the FEU's 2012 and 2013 revenue requirements. Further, the Commission Panel agrees with the BCOAPO that it would be of value for the FEU to file a financial analysis of the impact of variances in the forecast of customer additions on all rate classes when they file their next RRA and the FEU are directed to do so.

5.4 Commercial Customer Usage Rates and Demand Forecast

Individual average UPC forecasts are developed by the FEU for each service area for each commercial customer class. The volatility of UPC forecasts in the commercial sector is found by the FEU to be greater than for the residential sector due to the smaller number of customers and the large range of usage patterns. (Exhibit B-9, BCUC IR 25.3)

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. Commercial customer additions and the existing commercial customer totals are one 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. Commercial customer additions forecasting variances are, compared to UPC forecast variances, much more volatile and less predictable. The FEU attribute this to a variety of factors including the recession, existing customer turnover and the small number of new customers in commercial rate schedules. (Exhibit B-9, BCUC IR 25.3)

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. (Exhibit B-1, p. 85)

The position of CEC is the commercial UPC rate, like the residential UPC rate is too low.

Commission Determination

The Commission Panel approves the FEU's Commercial Energy Demand forecast for the purpose of calculating their 2012 and 2013 revenue requirements. The Panel notes that the forecast follows a previously approved methodology and more importantly, has provided reasonable results. In addition, the Panel notes that any UPC variances are managed through the RSAM, which protects the interest of ratepayers.

5.5 Industrial Customer Usage Rates and Demand Forecast

Consistent with past practice, the FEU forecasted industrial demand based on an annual demand survey requesting each industrial customer to provide its forecast short-term monthly consumption and long-term annual consumption. Recent improvements to the survey methodology have increased participation rates. The survey participants accounted for approximately 83% of industrial demand. The FEU are looking to further enhance the industrial survey response using an internet-based survey. (Exhibit B-6, BCOAPO IR 1.18.2) Other methods of forecasting industrial demand (e.g. GDP) are viewed as being less accurate. (Exhibit B-6, BCOAPO IR 1.17.1)

Commission Determination

The Commission finds the methodology used to forecast industrial demand to be reasonable and approves it for use in calculating the FEU's revenue requirements in 2012 and 2013.

6.0 OPERATIONS AND MAINTENANCE EXPENSES

6.1 Cost Drivers

Proposed Operations and Maintenance (O&M) Expenses are $268.1 million in 2012 (+7.6 percent) and $279.2 million (+4.1 percent) for 2013. The FEU state that overall O&M Expenses are influenced by a number of drivers with cost pressures resulting from different sources. The Companies have identified five areas which drive incremental funding requests:

- Labour inflation and benefits
- Codes and Regulations
- Customer and Stakeholder Expectations
- Demographics
- Service Standards and Reliability

(Exhibit B-1-3, p. 145)

These cost drivers are not unique to this Application as the FEU note they tend to be stable over time but specific items within the categories do change from year to year. (Exhibit B-6, BCOAPO IR 1.3.1)

6.1.1 Labour Inflation and Benefits

The FEU state that labour inflation and benefits costs needed to fund wage and benefits increases for employees are non-discretionary. They report that, in a labour market with increasing demographic challenges, the total rewards framework must be continually monitored so that the FEU can stay competitive with other employers. According to the FEU, their challenge is to attract and retain talented people in key positions without paying above market rates for other positions.

Overall, their cash compensation philosophy is to be at the median of their defined peer group. O&M labour and benefits increases for the test period as outlined in the Application in Table 5.3-2 (Exhibit B-1-3, p. 147) total $8.841 million in 2012, with an additional $2.467 million in 2013. The most significant area of cost growth is benefits, which accounts for an increase of $6.512 million in 2012 with a slight reduction of this amount in 2013. (Exhibit B-1, p. 146)

Commission Determination

The Commission Panel accepts the calculation of O&M labour and benefits increases as outlined in Table 5.3-2 of the Application.

6.1.2 Codes and Regulations

The FEU state that codes and regulations funding requirements are a function of the need to comply with existing codes as well as changes which are anticipated. Collectively, these define the Companies' level of reporting and compliance activities. The focus of these activities is on public, employee, property and environmental safety and system reliability. Overall, incremental cost increases for codes and regulations total $1.796 million in 2012 with a further $.854 million in 2013. Departmentally, most of these increased costs are in Distribution, Energy Solutions and External Relations, Operations Engineering and Operations Support. (Exhibit B-1, pp. 151-155, Exhibit B-1-3, pp. 156-158)

6.1.3 Customer and Stakeholder Expectations

Incremental cost increases for Customer and Stakeholder Expectations total $0.401 million in 2012 with a further $3.833 million in 2013. The FEU report that the increase in O&M expenses under this category is due primarily to the following:

- The in-sourcing of the Customer Services function.
- The Biomethane program and CNG and LNG fuelling infrastructures.
- Funding in support of the LTRP to meet increased regulatory requirements.
- Costs related to the regulatory process.

(Exhibit B-1, pp. 152-155, Exhibit B-1-3, pp. 156-158)

CEC expresses concern for the impact on rates of recent Commission Decisions with respect to NGV and the Commission launch of the AES Inquiry. The CEC argues that ratepayers have paid in their rates for the development and approval process as well as the Commission review and are now facing the removal of benefits which could be expected from the expansion of services. The CEC expects that when the expansion of services resumes, some of the benefits will flow to the shareholder and submits that this will be less than fair and reasonable given that ratepayers have paid for the process and lost the benefits, while the shareholder has gained from what it describes as a "flawed process." Its position is that ratepayer cost should be mitigated for any failed or delayed implementation of AES initiatives over the test period.

With respect to the Customer Care (CCE) initiative, CEC submits that, given the size of the cost increases related to this project, there is a need to ensure ongoing prudence in its execution. CEC submits, that the FEU have not done an adequate job of planning to pursue savings and benefits from this project. (CEC Final Submission, pp. 9-10) The Commission Panel will address this matter later in Section 6.4.3.

The FEU submit that significant efforts have been made to move AES Inquiry subject projects forward and believe they have acted appropriately with their initial applications and resultant approvals. The FEU further state that they have proposed mechanisms to protect ratepayer interests which have or will be considered by the Commission in proceedings related to NGV, Biomethane, EEC and TES. (FEU Reply, p. 24)

Commission Determination

The Commission Panel is sympathetic to the CEC's concern that the ratepayer may be asked to bear the risk for initiatives which either fail or are delayed. However, there is no evidence in this Proceeding to support the view that, in bringing these matters forward, the FEU have failed to consider the interests of ratepayers and should reasonably have foreseen the difficulties they have encountered. **Accordingly, the Commission Panel has determined that ratepayer cost should not be mitigated for failed or delayed implementation of AES initiatives.**

6.1.4 Demographics

The FEU report that the demographic challenges which are presented by an aging workforce will continue into the coming years and they will need to use greater effort to proactively recruit, train, transition and manage overall changes to the workforce composition. The FEU face the challenge of approximately one-half of their workforce being eligible to retire in the next 5 years with 663 employees being eligible for retirement between 2011 and 2016. The Companies report that the two departments facing the biggest immediate threat are Transmission and Distribution where 122 or 16 percent of employees are eligible to retire with unreduced pensions in 2012. The FEU observe that many of these employees hold positions in highly technical or specialized field positions requiring higher skill levels, are more difficult to recruit and demand longer training and knowledge transfer periods. Further, they point out that, in addition to this, over 40 percent of distribution managers are eligible for retirement with either reduced or unreduced pension benefits, contributing to the knowledge and experience loss.

The direct impact on the Human Resources Department for training, employee development and knowledge transfer as a result of these retirements and subsequent rehiring to fill the positions is significant. The Companies note that Human Resources will need to continue to work with department management to develop plans and strategies to mitigate these risks. Incremental funding required in this category totals $0.374 million in 2012 and $0.224 million in 2013. (Exhibit B-1, pp. 152-155, Exhibit B-1-3, pp. 156-158)

There were no Intervener submissions on this issue.

Commission Determination

The Commission Panel notes that this matter was raised in the 2010 and 2011 Revenue Requirements Proceeding where the FEU applied additional resources to the problem of demographics.[6] The concern of the Panel is not whether there is a problem but whether the FEU are taking adequate steps to address what has the potential to be a serious difficulty. Since the magnitude of this problem was foreseeable and has been at issue for some time, it is reasonable to expect that the Companies would have a developed a detailed plan on an area by area basis to ensure that the disruption related to impending retirements is minimized and the costs to deal with this over the longer term are known. **In the event such a plan exists, the Companies are directed to file it with the Commission as soon as possible and no later than June 1, 2012. In the event no such plan has been developed, the Commission Panel directs the FEU to prepare a plan with a 5-year time horizon, by Department, detailing the specific actions they will need to take, what the costs are estimated to be and a timeline estimate. The FEU are directed to file this plan by no later than August 1, 2012.**

6.1.5 Service Standards and Reliability

The Service Standards and Reliability cost driver category includes any costs required to support the ongoing integrity of the FEU's systems as well as any increases in non-labour costs inclusive of additional funding requirements for price escalation of service agreements and existing contracts. The major focus on system integrity is to be addressed through development of the Long Term

[6] In the Matter of An Application by Terasen Gas Inc. for Approval of 2010 and 2011 Revenue Requirements and Delivery Rates; Order G-141-09 dated November 26, 2009

Sustainment Plan (LTSP). Incremental cost increases for Service Standards and Reliability total $8.353 million in 2012 and $3.686 for 2013. (Exhibit B-1, p. 155, Exhibit B-1-3, pp. 156-158)

6.2 Retained PBR Benefits

As noted in section 4.2, the Commission recognizes that during the PBR period FEI was able to find significant cost savings to the benefit of customers and the shareholder. During this six-year period $67.5 million in benefits flowed to customers, while an equal amount flowed to the shareholder. FEI believes benefits flowing from PBR continue to accrue to customers. (Exhibit B-17, BCUC IR 2.2.2, FEU Final Submission, p. 25)

FEI claims the savings were achieved through a number of means, including:

- The Utilities Strategy Project (the adoption of combined utility management for the FEU);
- Deferring activities and related costs where safe and prudent to do so;
- Management of the meter to cash process resulting in the lowering of bad debts;
- Centralized asset management in Distribution services; and
- Department reorganization and streamlining.

(Exhibit B-17, BCUC IR 2.2.2)

FEI asserts that it continues to see lower costs in many areas from these initiatives, which are permanent in nature. However, FEI concedes that a number of the efficiencies that were realized during PBR can only be achieved once, or can only be sustained for a limited period of time before activities need to be resumed and costs need to be incurred. (FEU Final Submission, p. 25) Savings have also been offset by changing priorities and initiatives in many other areas in response to factors such as changes to codes and regulations, customer and stakeholder expectations, and energy policy. Capital expenditures and O&M in 2012 and 2013 are thus higher than during the PBR period. (Exhibit B-17, BCUC IR 2.2.2)

The FEU calculated what the Lower Mainland residential delivery rate would be in 2012 and 2013 if the 2003 delivery levy was increased by inflation. They found that the proposed delivery rates for 2012 and 2013 are within two percent of what they would have been under this pure inflation scenario. Based on this, and the fact that there have been increased expenditures to meet new requirements, changes in accounting standards and higher depreciation rates, overall rates have increased. Therefore, the FEU conclude they have been able to retain some of the cost reductions that were achieved during the PBR period. (Exhibit B-17, BCUC IR 2.2)

CEC submits that in 2010, immediately after the PBR period, FEI's O&M costs saw a significant increase of 11.33 percent and, from 2011 onwards, the O&M cost increases have remained consistently above four percent. (CEC Final Submission, p. 19, Exhibit B-1, Appendix D) BCOAPO submits that efficiencies achieved under PBR appear to be lost by 2009. (BCOAPO Final Submission, p. 12) CEC notes that the post PBR loss of savings benefits stands out. (CEC Final Submission, p. 20) BCOAPO and CEC both identify that any cost deferrals during the PBR period, as opposed to sustained cost savings, have a higher cost to customers than when they actually incurred. This is due to the PBR mechanism allowing the shareholder to take in 50 percent of the cost savings. Therefore, when the cost is incurred outside of the PBR period, the ratepayer, in effect, pays again resulting in a cost to the ratepayer of 150 percent of the actual expenditure. (CEC Final Submission, p. 19, BCOAPO Final Submission, p. 8)

The FEU note that some PBR cost savings achieved were related to the deferral of certain activities where it was considered safe and prudent to do so. However, they submit that the cost impacts of deferred expenses from PBR were minor and dealt with in the 2010-2011 period. (FEU Reply, p. 12)

In assessing the issue of the longevity of PBR benefits, the Commission Panel has reviewed the data provided by the FEU on historical and forecast O&M expenses. The following Table sets out the

O&M history and projections on a per customer basis. They have been calculated on both a nominal basis and a real basis. The percentage change from year to year was then calculated by the Commission using this data.

Table 6.1
Historical and forecast O&M Expenses by Customer
(000)

	Actual 2006	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Forecast 2011**	**Forecast 2012**	**Forecast 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	225,957	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**

(Source: Exhibit B-1, Appendix D-2)

Table 6.2
Percentage Change in O&M expenses by Customer[1]

	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
FEU Nominal O&M per Customer	**-2.6%**	**+2.6%**	**+2.2%**	**+6.8%**	**+3.6%**	**+4.2%**	**+3.7%**
FEU Real O&M per Customer	**-4.5%**	**+0.01%**	**0%**	**+4.9**	**+1.6%**	**+1.9%**	**+1.9%**

[1]The percentage is calculated by subtracting the O&M in the previous year from the O&M in the current year and then dividing the answer by the O&M in the previous year, and multiplying the result by 100.
(Source: Exhibit B-1, Appendix D-2)

Looking at the data, there appears to be a marked increase in the O&M per customer in the post PBR period (2010 to 2013) compared to the PBR period. In real terms, the change in O&M per customer was flat to negative during the PBR period but has increased consistently since that time. In nominal terms, the same pattern is evident with a clear increase in per customer O&M costs following the PBR period.

Commission Determination

The Commission Panel recognizes that it is not possible to definitively assess to what extent benefits achieved in the PBR period continue to flow through to ratepayers. As stated by the FEU, there have been a number of changed requirements imposed on the Companies and there are new areas of activity and concern that would make any straight forward calculation impossible. **However, the Commission Panel finds that the evidence indicates the benefits achieved during the PBR period have eroded.**

6.3 O&M Productivity Improvement

In Section 4.2, the importance of securing productivity improvements was discussed. A question raised was whether, in this Application, the FEU have demonstrated that they have optimized productivity levels. In the view of the Commission Panel, this question goes to the heart of the matter as it puts focus on the level of the FEU's commitment to improving productivity and keeping rates at the lowest reasonable level while maintaining acceptable levels of safety and reliability.

Throughout the Proceeding there has been much said by the Applicants and the Interveners with respect to the rate of growth of costs. As outlined in Section 6.2, the position of the FEU is that many of the initiatives which were undertaken to reduce costs during the PBR period continue to result in savings, although they acknowledge that in some instances cost savings can only be sustained for a limited period of time and activities must be resumed.

In the view of the Commission Panel, the most important lesson to be learned from the PBR period was not specifically addressed by any of the parties. We refer directly to the success of PBR. Within the PBR period a process was developed to determine what was considered to be a reasonable cost base for each of the six years covered by PBR. Over this period, the FEU not only met the challenge but improved upon budgets by a total of $135 million ($67.5 million for the ratepayers and $67.5 for the shareholder.) (FEU Reply, p. 11) It has been argued that both the ratepayers and the shareholder received benefits related to this saving, a point which all of the parties acknowledge. However, the Commission Panel believes the success was not only in the amount of savings which was achieved, but perhaps more importantly, in the fact that when presented with a challenge, the FEU took the necessary steps to ensure the cost targets set during PBR were not only met but consistently exceeded. Moreover, this was achieved with no indication that the safety or reliability of the system was in jeopardy.

The FEU submit that there are two features of the O&M budgeting process which were emphasized by witnesses during the Oral Hearing. The first of these was that the process was bottom up and iterative rather than top down, and the second was the use of various budgeting techniques including zero-based and trend-based budgeting. The FEU rely on the evidence of Mr. Dall'Antonia. Mr. Dall'Antonia explained that where there is a material variance in activity from year to year, the existing budget is revisited to a greater degree, while in those areas where the level of activity is steady and predictable, trend-based budgeting is used to a greater extent. Further, the Companies submit that in activity-driven budgets a zero-based approach is key to ensuring the existing budget is still warranted. The FEU argue that the hybrid approach employed by the Companies is cost-effective while applying the necessary rigor. (FEU Final Submission, pp. 18 -22)

CEC argues that if productivity improvements are not identified in plans and targets, they are highly unlikely to occur. Further, CEC submits that the budget process as described in the budgeting guideline documents fails to adequately establish productivity expectations. In summary, CEC submits that, while the FEU's stated commitment to productivity is laudable and appropriate, the Commission should find that the budgeting guidelines and process as well as the performance measurement and tracking are less than adequate to assure the level of productivity improvement the Companies are seeking. In accordance with this, CEC submits the Commission should set rates based on lower O&M (as well as Capital Rate Base Values) than those applied for by the FEU. (CEC Final Submission, pp. 11-18)

The FEU state that the CEC's arguments regarding productivity have been generally made without reference to any evidence. The Companies submit that the evidence demonstrates they have forecasted fair and reasonable costs to provide customers with safe and reliable service. The Companies outlined a number of examples of productivity improvements, identified in evidence, which they believe are representative of their approach to finding ways to reduce costs to ratepayers. (FEU Reply, pp. 1-2)

Commission Determination

The Commission Panel acknowledges that the FEU can point to activities or actions undertaken within the Companies that have resulted or may in the future result in more efficiency or lower cost. However, the concern of the Commission Panel is the lack of a systematic approach to managing down existing costs and the lack of description as to how the commitment to productivity management fits in with the budgeting process. The Panel agrees with CEC's assertion that if productivity improvements are not identified as part of the planning and budgeting process, they are unlikely to occur. In our view, the effort expended by the FEU during PBR is a very good example of what can be accomplished if the will and the desire to manage costs downward exists. As noted previously, savings during the PBR period totalled $135 million which, on an annual basis, amounts to an average of $22.5 million per year. Moreover, the Commission Panel notes that in the 2010 and 2011 Revenue Requirements Negotiated Settlement Agreement, the parties agreed to O&M reductions from budgeted amounts totalling $4.0 million in 2010 and $5.5 million in 2011 without compromising safety or reliability. Because of these factors, the Commission Panel is not persuaded that the FEU have done all they can to optimize productivity levels and manage cost levels down.

Accordingly, the Commission Panel directs the FEU to reduce O&M expenditures for each of 2012 and 2013 by $4.0 million. In the view of the Panel, a $4 million reduction (1.53 percent) is very achievable from a total proposed $261.1 million in O&M expenses, especially given the past history of the PBR period. Where these cost reductions are applied is left to the discretion of the

Companies. These reductions will be increased by any further reductions which are directed as a result of the review of new activities and initiatives at the departmental level. The Commission Panel further directs the FEU to file a Productivity Improvement Plan with their next revenue requirements application. The Productivity Improvement Plan may take the form of a proposal for PBR which places emphasis on both-short term activities as well as long term, sustainable improvements.

As noted in Section 4.2, one of the matters that the Commission must have due regard to in setting a rate is to encourage public utilities to increase efficiency, reduce costs and enhance performance. In making this determination, the Commission Panel is taking into account that requirement.

6.4 Departmental Cost Review

6.4.1 Operations

The Operations Department is made up of three areas: Asset Management, Distribution and Transmission. The role of the Asset Management Group is to provide both planning and oversight management of the installation, operation and maintenance of the FEU's distribution and transmission assets. The Distribution Group is responsible for the provision of safe, reliable, cost effective service to gas customers through the installation, operation and maintenance of the gas distribution system. Distribution activities are organized into four functions; emergency management, installation and renewal of distribution assets, operations and maintenance and account services. The Transmission Group has responsibility for delivery of natural gas to the distribution network as well as the operation and maintenance of mainline pipelines, compressor stations and LNG plants. (Exhibit B-1, pp. 160-164)

Distribution Group (includes Asset Management)

The FEU project O&M costs for Distribution to be $54.086 Million (+9.6 percent) in 2012 and

$57.980 million (+7.2 percent) in 2013. Most of the growth in cost is in the Mainland and Vancouver Island regions. The Companies project the need for employees to increase from the projected base of 658 employees in 2011 to 661 in 2012 and 670 in 2013. Employee numbers are broken into two groups: Capital/Deferral employees, who work on capital projects and those whose work relates to ongoing O&M activities. Worthy of note is the fact that in 2011 the base level of employees (658) exceeded approved levels by 34 employees. Of these, 20 were related to the conversion of former contractor positions to employees. The FEU state that this was done to increase the efficiency and flexibility of work crews. In addition, the FEU note that there were 10 planning and appointment setting positions added to the Operations centre to support existing programs. In addition to their employees, the FEU also rely upon and include in their O&M budgets a range of contractor services including contractor consultants (approximately 45 employee equivalents). The FEU also have a secondary workforce consisting primarily of two major installation contractors and a number of other contractors. These contractors provide a peak shaving resource for the capital workload which the FEU state is more seasonal and unpredictable than normal O&M work. (Exhibit B-1-3, p. 165, Exhibit B-1, pp. 166-167) The embedded cost for these contractor/consultants totals $4.349 million in 2012 and $5.474 million in 2013. (Exhibit B-9, BCUC IR 1.49.1)

With respect to codes and regulations, FEI is requesting $120 thousand for a color change in right-of-way signage in 2012, $250 thousand for additional Asset Compliance Managers and a further $350 thousand for a lock and security device program which will include Vancouver Island. (Exhibit B-1, p. 172)

As noted previously, the FEU have identified demographics as a significant challenge for the Distribution Group where 90 employees remain eligible to retire. The Companies state that they expect further retirements by the end of 2013 and have requested $160 thousand in 2012 and $270 thousand in 2013 to address the challenge this will create. In addition, a further $90 thousand in 2012 has been requested by the Mainland group to hire an additional resource to manage and administer the recently introduced peer training program plus $200 thousand in 2013 for the required training. Further, with more than 40 percent of management becoming eligible to retire in 2012, the Companies are proposing $70 thousand in both 2012 and 2013 for a Manager-in-Training program.

The FEU state that in order to meet service standards and provide safe and reliable service, additional resources and investment are required. Specifically, the Companies require $448 thousand in 2012 and a further $58 thousand in 2013 O&M to hire additional resources to manage the workload and maintain service standards in the Operations Centre group. In 2012, three Planners and three Operational Support Representatives (OSRs) are required, with an additional three Planners required in 2013. The FEU submit that the Asset Management Group requires an additional two employees at a cost of $160 thousand in 2012 and a further two at a cost of $140 thousand in 2013. These roles are to support O&M, capital and sustainment planning as well as the Biomethane program. The FEU have also requested a further $416 thousand in 2012 and $272 thousand in 2013 for Field Service Delivery, the largest component of the Distribution budget, to support changes in activity levels and unit costs. In addition, FEVI requires an additional $353 thousand in 2012 and on top of this, $402 thousand in 2013 with most of the expenditures designated for repairs to the Bay Street Bridge crossing in Victoria.

The FEU have added a new area within Preventive Maintenance for the operation and maintenance of Biomethane and NGV assets. Requirements to support NGV (specifically, CNG and/or LNG stations) total $115 thousand for both 2012 and 2013. Biomethane assets will require a further $23 thousand in 2012 and $68 thousand in 2013 as the number of assets to be maintained increases. (Exhibit B-1, pp. 172-173, Exhibit B-1-3, pp. 174-175)

A major initiative being undertaken by the FEU is that of developing a long term view of system sustainment. They report that the previous focus of asset management was on a one to five-year planning horizon. The Companies wish to take a longer term view of system sustainment to more effectively address issues such as infrastructure age, ongoing compliance with codes as well as customer, public and stakeholder expectations. The Companies state that incremental funding in the amount of $1 million in 2012 and $500 thousand in 2013 is required to conduct a system sustainment assessment. To support this initiative, Asset Management will require one engineer and two analysts in 2012 at a cost of $150 thousand and an additional analyst in 2013 at a cost of $45 thousand. (Exhibit B-1, pp. 161-162, 176)

Commission Determination

On review of the evidence, the Commission Panel has a number of areas of concern with respect to the proposed increase in Distribution costs. A discussion of these follows:

i) Asset Compliance Managers

The FEU state that asset compliance management is a requirement under the Integrity Management Plan which evolved to meet Canadian Standards Association (CSA) Z662 code requirements as well as safety and reliability objectives. Two such positions were put in place in 2011 and three more are requested for 2013. This will allow one compliance manager to work in each of five operational zones. Of concern to the Panel is the Companies' submission that while the type of work among zones is consistent, there is considerable variation in the number of work activities. (Exhibit B-9, BCUC IR 1.51.2, Exhibit B-1, p. 172) In the view of Panel, because of the variation in activity levels, there should be no requirement to assign a specific Asset Compliance Manager to each zone. From the evidence presented, it seems reasonable that Asset Compliance Managers will go where and when needed, and there appears to be no reason why there is a requirement for an Asset Compliance Manger to be assigned to each region. The Commission Panel accepts that there is an expanding need for this function given the level of turnover within the organization but is unconvinced there is sufficient evidence to suggest that the number should increase from two to five in 2013. The Commission approves two of the three new compliance management positions for 2013. **The Commission Panel approves expenditures of $168 thousand for two of the three new Asset Compliance Manager positions in 2013 (two thirds of the $250 thousand requested for these positions).**

ii) Demographic Challenges

The Commission Panel notes that the FEU are facing a significant challenge presented by the potential for a high number of retirements. The Panel accepts that the impact of this will not be mitigated without the expenditure of some funds to more effectively manage an orderly transition. The steps taken by the Companies with the development of a peer training model and the stated intention of developing a Management-in-Training program are initiatives which are likely to prove useful over the ensuing few years.

As mentioned previously, the Panel remains concerned with the lack of a comprehensive plan detailing the size of the problem over time, the range of initiatives being taken and the timelines for these activities. The Companies have requested significant incremental O&M funds of $160 thousand in 2012 and a further $270 thousand in 2013 to address this issue but provided little detail as to where these funds are to be applied. It is expected that the five year plan as directed in Section 6.1.4 will outline the purpose of these funds for both the current test period and identify further funds which may be required in the future.

iii) Additional Planners

As noted, the FEU propose to hire three additional Planners in both 2012 and 2013 plus an additional three OSRs at a cost of $448 thousand in 2012 and $58 thousand in 2013. The Commission Panel is concerned as to whether there is a need for these additional employees and whether there is a corresponding return related to putting these new positions in place. The FEU explain their function: "[t]he Planners who typically meet on construction sites with homeowners, developers and municipalities to design and cost estimate gas system infrastructure, are required for capital activities; however, they also engage in training, supervision and reviews of municipal project plans which are classified as O&M activities." (Exhibit B-1-3, p. 174) The FEU testified that more and more Planners are required to make field visits resulting in greater use of the Planner group. (T7: 1178) However, the Commission Panel notes that the growth of this planning activity is at a time where the number of new customer mains being constructed has dropped steadily (since

2007.) (Exhibit B-42) Further, the Commission Panel notes that the FEI expects that sustainment capital expenditures will grow at a faster rate than that of the growth of the Planner group. (Exhibit B-50) Of concern to the Commission Panel is that FEI has not addressed the fact that it wished to increase Planning group numbers at a time when the number of new customer mains being constructed continues to drop. The Commission Panel understands that some of the work related to sustainment capital expenditures will offset some of the time savings related to the drop in the number of new customer mains and related planning work. However, in Panel's opinion, the Companies have not adequately addressed this nor have they convinced the Panel of a need for six rather than a lower number of Planners. **For these reasons, the Commission Panel does not accept that the need for the full number of requested employees has been established and has determined that it will only approve two rather than three additional Planners in each of 2012 and 2013. The Commission Panel directs FEI to reduce the O&M budgets by one FTE Planner position in 2012 and 2013 to reflect this**.

The Commission Panel approves all other applied for incremental expenses for Distribution and Asset Management.

<u>Transmission</u>

The FEU project total O&M costs for Transmission to be $16.280 million (+9.0 percent) for 2012 and $17.499 million (+ 6.6 percent) in 2013. Total employees for Transmission are forecast to be 92 in 2012 (+7 percent) and 94 in 2013 (+2.1 percent). The FEU state that the need for additional employees since 2010 is a result of two factors. First, the completion of the Mt. Hayes LNG facility created a requirement for 10 new operators to handle daily activities. In addition, there is a need for four more employees for Transmission in 2012 and another two employees in 2013. The four additional employees in 2012 are for management and field staff to deal with the expected increase in asset management activities once the scope and timing of future asset renewals have been determined. Of the two new employees required in 2013, one is to replace a retiring outside contractor and the other is a technician required to operate the Vancouver Island transmission system. (Exhibit B-1, pp. 179-180)

With respect to codes and regulations, FEI is projecting a decrease in O&M as there were a number of non-recurring initiatives which were completed in 2011. The projected saving of $250 thousand however, is offset by a $120 thousand increase to begin the change of transmission pipeline signage in order to meet the American National Standards Institute ANSI Z535.1. This $120 thousand will be an annual requirement until the project is complete in five years. (Exhibit B-9, BCUC IR 1.50.1) In 2013, vegetation control costs are expected to decrease by $150 thousand but this will be partially offset by an increase of $75 thousand for recertification of the pressure safety valves used in the Transmission compressors. The Companies note that Vancouver Island is also eliminating a number of non-recurring activities which reduces costs by $187 thousand in 2012 but requires an additional $20 thousand for the pipeline signage initiative and $75 thousand for vegetation growth control. (Exhibit B-1, pp. 183-185)

An additional annual O&M cost of $133 thousand in 2012 plus an additional $106 thousand in 2013 has been forecasted for the NGV service program to cover the costs of increased liquefaction to replenish the Tilbury LNG tank levels. This amount will be offset by incremental revenue earned through the provision of this service through Rate Schedule 16. (Exhibit B-1, p. 183, Appendix I, p. 9)

Due to previously noted demographic challenges, Transmission requires three transitional employees to manage a number of field workforce retirements that are expected over the test period. It is assumed that a six month transition period will be necessary, with two employees required in 2012 and one in 2013. The estimated cost for these employees is $91 thousand in 2012 which will be partially offset by a $46 thousand decrease in 2013. The FEU state this is being done because of the difficulty of recruiting and training new employees to replace those retiring. (Exhibit B-1, p. 183, Exhibit B-1-2, p. 184)

Mainland requires an additional $1.005 million in O&M funding in 2012 while a further $1.048 million is required in 2013 to meet Service Standards and Reliability. The FEU report these costs are made up of $180 thousand for inflation on materials and the need for additional system sustainment resources totalling $1.1 million in 2012. An additional $185 and $803 thousand for inflation and system sustainment costs will be required in 2013. Offsetting some of these costs are savings in Own Use Fuel required to operate the Companies' compressors which benefit from favourable forward market natural gas prices. Vancouver Island Transmission requires an additional $693 thousand in incremental O&M for 2012 and $201 thousand in 2013 to meet objectives related to Service Standards and Reliability. These amounts are made up of inflation on materials, the need for pipeline employees and $166 thousand for existing Mt. Hayes LNG plant operators who were previously able to capitalize a portion of their labour costs. In addition, the Mt. Hayes facility is expecting electricity cost increases (net of fuel gas savings) of $242 thousand in 2012 and a further $40 thousand in 2013. (Exhibit B-1, p. 183, Exhibit B-1-2, pp. 184-185)

There were concerns raised by Interveners with respect to the right-of-way signage. BCOAPO notes that FEU is moving forward to complete this requirement in spite of the fact that compliance with ANSI standard Z535.1 is not required by any certain date. BCOAPO have requested the Commission reduce funds for this project to engage in a slower, more strategic program until compliance with Z535.1 code is achieved. (BCOAPO Final Submission, pp. 14-15)

The FEU submit that it is reasonable to replace the signage over five years and to extend this period will result in minimal cost savings while increasing the unnecessary risk of non-compliance. (FEU Reply, pp. 21-22)

Commission Determination

The Commission Panel agrees with the FEU that the planned replacement of signs over a five-year period is reasonable. The Panel is not convinced there is any merit in trying to achieve the required color change during the normal replacement cycle and agrees with FEU that this would likely result in a 'hit or miss' upgrade of the colors. (Exhibit B-50) **Accordingly, the Commission Panel accepts the need for the replacement of the right-of-way markers and is satisfied that FEU is handling the timing of the upgrade program in a reasonable manner.**

The FEU continue to request additional funds of $133 thousand in 2012 and a further $106 thousand in 2013 (totalling $239 thousand as outlined in the Application) to cover the costs of increased LNG liquefaction requirements despite the reduced LNG Service volumes set out in the September 12, 2011 Evidentiary Update. (Exhibit B-1, p. 183, FEU Final Submission, p. 50) **The Commission Panel notes the position the FEU have taken with respect to the further development of this business. There is no evidence of any further increase in LNG sales which are forecasted beyond the Vedder LNG refuelling station. Therefore, the Panel accepts a proportionate share of the $133,000 requested for 2012 and in 2013 the amount of $48,000, and rejects the $106,000 request for 2013 in its entirety. In addition, the Panel confirms that in keeping with the CNG/LNG Decision (Order G-128-11),[7] FEU must ensure that any incremental O&M costs associated with LNG liquefaction are recovered under Rate Schedule 16.**

The Commission Panel approves the remainder of the incremental expenses requested for the Transmission group.

6.4.2 Energy Supply and Resource Development

The FEU project an annual operating and maintenance budget for the Energy Supply and Resource Development (ESRD) department of $4.043 million in 2012 and $4.296 million in 2013, representing an increase of 5 percent over 2011 (forecast and approved), with an additional forecast increase of 6.3 percent in 2013 over 2012. (Exhibit B-1, p. 188)

An additional two employees are expected to be required after 2011 for this group, one in 2012 and the second one in 2013. (Exhibit B-1, p.188)

Other than standard labour inflation and benefits, the primary cost driver for the increase in the

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[7] In the Matter of An Application by FortisBC Energy Inc. for Approval of a Service Agreement for Compressed Natural Gas Service with Waste Management of Canada Corporation and General Terms and Conditions for Compressed Natural Gas and Liquefied Natural Gas Service; Decision and Order G-128-11 dated July 19, 2011 (CNG/LNG Decision)

ESRD relates to the Service Standards and Reliability cost driver. Specifically, ESRD requires an additional $84 thousand in O&M funding in 2012 and an additional $154 thousand in 2013. This cost increase relates to FEI's request to add one employee each in 2012 and 2013. FEI's projected costs assume that each employee will be hired mid-year. (Exhibit B-1, p. 189) The FEU submit that both these employees will also work as business development specialists and are needed to assist the Resource Development group to meet its objectives. In 2011, FEI have added two new employees as business development specialists to help the Resource Development group with work identifying and developing new regional projects as well as system infrastructure projects. (Exhibit B-1, p. 188)

In response to BCUC IR 1.58.1, the FEU further describe the nature of Resource Development as follows: [it] "is a small group of specialized resources responsible for identifying and transitioning, from concept to construction, large-scale, multi-year, system infrastructure projects often requiring a high degree of complexity, including pipeline, compressor, and storage. For example, the group would develop a Certificate of Public Convenience and Necessity (CPCN) application requiring the analysis of multiple alternatives, a high degree of stakeholder consultation, and involvement of multiple agencies. There are numerous reasons for these projects, including factors that address capacity, gas supply, system reliability, operational flexibility, aging infrastructure, safety, and environmental stewardship."

In BCUC IR 1.58.2, the FEU were asked if the Resource Development Group plays a role in any TES, NGV, and/or Biomethane or similar non-traditional utility operations. The FEU's response was a reference back to the response to Information Request 1.58.1

> "The core work completed by this group is not related to Thermal Energy Services, NGV, and/or Biomethane or similar operations. However, if an expansion of the supply infrastructure was required to support these operations, then Resource Development would become involved."
> (Exhibit B-9)

In total, since 2011 the FEU have increased their ESRD business development staff by 2 employees and propose to add an additional two more employees during the test period for a total of 4 additional business developers by the end of 2013. The Commission Panel has a number of concerns with the ESRD evidence presented in this Application. The Commission Panel notes that the two additional business developers in 2011 were not approved, and were hired at a time when the FEU did not experience significant customer growth or development of their traditional gas business. While the Panel accepts that the positions added in 2011 provided support to the Companies initiatives, we have concerns as to whether the additional two business developers requested are required.

Commission Determination

The FEU's evidence suggests that the core work of the Resource Development Group will not relate to TES, NGV or Biomethane. However, if supply infrastructure required expansion to support TES, NGV or Biomethane, this group would become involved.

In this Proceeding, the Commission Panel finds that FEU did not provide sufficient detail to support how the involvement of the Resource Development Group has been forecasted or allocated between traditional gas services and TES services. The Commission Panel is also not persuaded that an adequate attempt to forecast allocation among the different costs of service as they relate to TES, NGV and Biomethane has been made and is therefore is not convinced that the full amount of this cost should remain in the O&M of the FEU.

Also, given the relatively flat forecasted customer growth in the traditional gas business, the Commission Panel is not persuaded that the FEU have justified the addition of more business developers at this time. While the FEU may have additional asset replacement needs in the near term, the Commission Panel is not convinced that asset replacement necessarily requires business development activities.

Accordingly, the Commission Panel denies the two proposed additional business developers, one in 2012 and one in 2013 costing approximately $84 thousand in 2012 and $154 thousand in 2013, which represents the direct cost of the positions.

6.4.3 Customer Service

The FEU project an annual operating and maintenance budget for the Customer Service Department of $60.8 million in 2012 and $64.7 million in 2013, representing a decrease of 30 percent over 2011 (forecast and approved), with an additional forecast increase of 6.5 percent in 2013 over 2012. (Exhibit B-1, p. 193)

The Customer Service Department is described in the Application as playing "a vital role in providing service to customers, and consequently represents a core element of the business." (Exhibit B-1 p. 190)

For 2012, the FEU advise that the decrease of approximately $1.9 million is due to the change over to the in-sourced delivery model. (Exhibit B-1, p. 194)

The Customer Service Department function itself has, for the most part, been outsourced to Customer Works Limited Partnership for a number of years. In June 2009, FEI applied for a CPCN to repatriate the customer service function. The CPCN was granted by Order C-1-10 and the FEU have begun implementation of the Customer Care Program and commenced operation of two new Customer Contact Centres, one in the Lower Mainland and the other in Prince George.[8] The FEU have described the new in-sourced framework as enabling them "to better meet the current needs of [their] customers, with the ability to efficiently adapt to customers' needs as they change over time." The Customer Service Department was formerly a division of the "Energy Solutions and External Relations Department" which itself was formerly known as the "Marketing and Business

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[8] In the Matter of An Application by Terasen Gas Inc. for a Certificate of Public Convenience and Necessity for the Customer Core Enhancement Project Insourcing of Customer Care Services and Implementation of a New Customer Information System; Decision and Order C-1-10 dated February 26, 2010 (CCE Decision)

Development Department." (Exhibit B-1, p. 191)

The two new Contact Centres, which are at the heart of the new customer service framework, are described in the Application as providing the Companies with 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." (Exhibit B-1, pp. 194-195) They forecast that while in-sourced delivery model savings will continue in 2013, these amounts will be offset by additional costs due to the disappearance of the joint gas and electric manual meter reading arrangement with BC Hydro as the electric utility moves to its Smart Metering Initiative. (Exhibit B-1, p. 194)

CEC submits that the FEU have not adequately planned for nor pursued benefits from the in-sourcing delivery model and that further productivity gains should be made. (CEC Final Submission, p. 10)

The FEU submit that the in-sourcing delivery model has been a success and point to a number of areas of benefit such as the reduced O&M costs forecast in the Application. (FEU Reply, p. 24)

Commission Determination

The Commission Panel has reviewed the evidence and notes that the two new Contact Centers were scheduled to open in January of 2012. We expect there will be a "breaking in" period where the FEU will review performance levels and serviceability and make adjustments based on what is working and what is not. Therefore, while the Panel may agree directionally with the CEC regarding the maximization of productivity benefits with the in-sourced model, we believe it would be premature to direct the FEU to pursue new initiatives to raise productivity at this time. **Accordingly, the Commission Panel approves the Customer Service O&M budgets as proposed. However, the Panel expects the FEU to address the matter of leveraging the Customer Care function to maximize productivity opportunities in the next revenue requirements application.**

This should provide ample time for stabilization of the system and a better understanding of potential opportunities.

Subject to the determinations made elsewhere in this Decision, the Commission Panel is satisfied with the FEU's forecast for the Customer Service Department's O&M budget.

6.4.4 Operational Engineering

The FEU project an annual O&M budget for the Operational Engineering Department of $14.753 million in 2012 and $15.310 million in 2013, representing an increase of 5.6 percent over 2011 (forecast and approved), with an additional forecast increase of 3.6 percent in 2013 over 2012. (Exhibit B-1, p. 228)

In 2012, the FEU forecast the need for 3 additional employees above 2011 approved levels and the reduction of one employee in 2013. (Exhibit B-1, p. 229)

The FEU submit that the increase in Operational Engineering costs is due to a number of drivers, including labour inflation and benefits, codes and regulation and shared services and reliability. The FEU forecast additional costs of $533 thousand in 2012 and an additional $44 thousand in 2013 for compliance with codes and regulations relating to BC One Call, the mapping of the gas distribution system and new requirements imposed by the *BC Oil and Gas Activities Act*, SBC 2008, c. 36. (Exhibit B-1, pp. 231-232)

Additional costs related to shared services and reliability amount to $242 thousand in 2012 and $135 thousand in 2013 and are due to the addition of resources to support the Long Term Sustainment Plan (LTSP) process. (Exhibit B-1, pp. 231-232) In order to facilitate that process, the FEU project adding 1.6 full time employee equivalents in 2012 and 2.2 full time employee equivalents in 2013. These employees will be engaged in providing non-capital project support relating to the LTSP. (Exhibit B-9, BCUC IR 1.57.1)

The CEC submits that cost increases in this department are of some concern, particularly labour rates for FEVI employees. CEC further notes that, in setting rates, it would be reasonable for the Commission to expect a one percent productivity improvement in this department. (CEC Final Submission, p. 33)

Commission Determination

The Commission Panel approves the O&M budget for the Operational Engineering Department for the test period. The LTSP will be addressed in Section 6.7.2. The Commission Panel observes that the departmental budgeting process and rationale for costs of Operational Engineering is generally well explained in the evidence. Further, the Commission Panel notes that the historic results of Operational Engineering have been thoroughly described which provides the Commission Panel with a better understanding and a measure of confidence in the additional resources requested for that department.

6.4.5 Energy Solutions and External Relations

The FEU project an annual O&M budget for the Energy Solutions and External Relations (ES&ER) department of $19.080 million in 2012 and $20.132 million in 2013, representing an increase of 20.5 percent over 2011 (forecast and approved), and an additional forecast increase of 5.5 percent in 2013 over 2012. (Exhibit B-1, p. 209)

The Corporate Marketing and Communications group has responsibility for internal and external communications strategies and standards and media relations. This group has undertaken initiatives in, among other things, safety education messaging. (Exhibit B-1, p. 206)

The ES&ER group manages key customer accounts and customer relations. It communicates with customers about service options and new service initiatives including EEC program opportunities. The Community, Aboriginal and Government Relations group fosters relationships with communities, municipalities, First Nations, business associations, government ministries and other organizations which regulate the energy industry, health and safety, and the environment.

The Market Development group identifies and develops new energy services products such as the Biomethane initiative and NGV fuelling. EEC programs are developed, implemented and tracked by this group. This group also monitors technological developments and energy policy.

The Resource Planning and Market Assessment group is responsible for forecasts of energy demand and supply and also develops the Companies' LTRP. (Exhibit B-1, pp. 206-209)

The FEU submit that three activities are driving the cost increases in this department. These are: a public safety education initiative that the FEU plan to expand in the test period, increased engagement in the LTRP process and the Biomethane service offering. (Exhibit B-1, p. 212)

A number of the factors driving the costs of this department are addressed elsewhere in this Decision, such as Alternative Energy Solutions spending, including ES&ER costs which are addressed in Section 7.2.

Also, the Commission Panel acknowledges that certain costs related to the Biomethane service offering were addressed in the Biomethane Decision[9] on a test basis. This program will be subject to a review during the test period. Any changes in the treatment or approvals of Biomethane service offering costs will be addressed at that time.

Other than the LTRP and areas addressed elsewhere in this Decision, the Commission Panel approves the O&M budget for the ES&ER department for the test period as the Commission Panel supports the Companies initiatives to increase public safety education.

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[9] In the Matter of An Application by Terasen Gas Inc. for Approval of a Biomethane Service Offering and Supporting Business Model and for the Approval of the Salmon Arm Biomethane Project and for the Approval of the Catalyst Biomethane Project; Decision and Order G-194-10, December 14, 2010 (Biomethane Decision)

On review of the evidence, the Commission Panel has a number of areas of concern with respect to the proposed increase in costs related to the LTRP. These include the following:

- The magnitude of additional expenditure being proposed by the FEU for additional staffing and other requirements;
- The apparent lack of integration between the strategic planning and resource planning initiatives as they have been described.

The FEU state that their stakeholders "are seeking a much greater depth of research and analysis in [their] long term resource plan than [they] currently have the capacity to provide." In the Companies' words, the feedback from this group during the regulatory process for the LTRP has highlighted a need for a broader examination of potential future outcomes and new analysis. It is the FEU's position that in order for them to comply with directives from the 2010 LTRP Decision and implement additional initiatives to improve the resource planning process, they will need an additional seven employees with a total corresponding cost of $2.7 million over 2012 and 2013. This is broken down in 2012 as approximately $555 thousand in labour and $645 thousand in non-labour costs totalling $1.2 million. In 2013, an additional $300 thousand in labour is requested reflecting a full year of staffing. (Exhibit B-1, p. 215)

In commenting on how future resource plan submissions could be improved in the 2010 LTRP Decision, the Panel in that proceeding made the following observations:

> "In the view of the Panel, the long term resource plan is an integral part of the strategic planning process. If prepared in sufficient scope and detail it will provide a solid framework upon which to base future decision making. In providing a more robust LTRP, Terasen will provide the stakeholders the opportunity to conduct a more meaningful examination of the longer term future." (2010 LTRP Decision, p. 19)

In making these observations, the Panel was signalling to Terasen that the LTRP is strategic in nature in that it should define where the utility is going, why it is going there, how it intends to get there, and the impact on the company's ratepayers. This was evident in the directives the Panel made with respect to what was to be included in the next LTRP. These directives were summarized under three categories; Terasen Utilities (now FEU) – a 20-Year Vision, GHG Reduction Targets – EEC Planning and the impacts of New Initiatives and New Business Environment and the Approach to Demand Forecasting. (2010 LTRP Decision, pp. 23-25)

The Companies have provided a listing and brief description of incremental budget items with respect to the Commission directives in Table 5.3-41. (Exhibit B-1, pp. 215-216)

The LTRP was explored in some detail within the IR process as well as in the Oral Hearing. The FEU, in describing the existing process, stated that currently, the resources dedicated to the preparation of the LTRP total one full time employee and one shared analyst position. (Exhibit B-1, p. 215 FN 88) In addition, the FEU stated that in the past, 30 to 40 employees provide input into the document over a temporary period during the resource planning process. (Exhibit B-9, BCUC IR 1.68.2) Going forward they expect no change in the number of people involved. With respect to the required resources, Mr. Bennett testified that the companies have the skill-sets but don't have the capacity. (T6: 917-918)

The FEU submit that the Commission's directives will require a more centralized planning function and the additional staffing will be used to develop new end use forecasting methods, prepare and report on new forecasts and compare new and existing forecast methodologies. They further submit that the seven proposed new employees will be fully engaged in the long term planning process. (FEU Final Submission, p. 67) None of the Interveners commented directly on the level of expenditure required to complete the resource planning process. However, CEC did submit that the benefits of the LTRP "may well be substantial and deliver major benefits to customers."
(CEC Final Submission, p. 31)

During the Oral Hearing, FEU President and CEO, Mr. Walker, when asked to describe the strategic planning process, was clear in outlining in broad terms how it worked, who was involved and how it was integrated with the business plan and ultimately vetted through the Board of Directors. When asked further to explain how the LTRP process fit in with this, Mr. Walker was much less precise. (T2: 253-255) The Commission Panel is concerned that the lack of clarity and precision may be an indication that there is limited integration between the two processes and the purpose of the LTRP is to fulfil regulatory requirements only.

Commission Determination

The Commission Panel supports improving the planning process required to prepare the next LTRP. We also understand that this may require employing additional resources, both financial and human. However, the Panel is not persuaded that the level of expenditure being proposed to achieve this is necessary. In their evidence, the FEU have outlined work which must be completed but have provided no detailed information with respect to the complexity of each directed task, the time required to complete the work or any additional cost estimates for reports or surveys. The FEU have also made the point that the seven new employees will be fully engaged with the LTRP process but did not go into detail to describe why seven as opposed to a lesser number of people were required for this task.

Mr. Stout testified that the current strategic process is not as robust as what is being considered with resource planning and this work will better inform the strategic process. (T6: 969) The Commission Panel agrees with Mr. Stout’s assessment and believes there is an opportunity for the two processes to be integrated. This, along with the apparent lack of clarity as to how the strategic and long term resource planning processes are integrated, leads the Commission Panel to the conclusion that there is an opportunity for the two processes to be more closely integrated. The subject of much of the resource planning process is very strategic in nature and the LTRP, if done correctly, should outline the Companies’ direction and longer term business initiatives and it therefore follows that it is a subset of strategic planning.

While the Panel accepts that there is substantial work to be completed, the lack of detail with respect to a work plan fails to persuade us that seven people will take two years to explore options and develop a plan detailing FEU's future resource needs. Therefore, the Commission Panel does not accept that the need for the $1.2 million in 2012 and $1.5 million in 2013 for this project has been adequately supported. Moreover, because there is an opportunity to more closely integrate the planning processes within the FEU, it is reasonable to expect that there are opportunities for savings which have not been previously considered. It is for these reasons **the Commission Panel will only approve additional funding in the amount of $400 thousand in 2012 and $600 thousand in 2013 for resource planning of the $1.2 million requested in 2012 and $1.5 million in 2013.** The difference between 2012 and 2013 approved amounts reflects the fact that it will take some time to organize this initiative and recognizes the need for a ramp–up period.

While significantly reducing the FEU's proposal to fund the resource planning process, the Commission Panel notes that it has left $1 million dollars to support this process. This is a substantial amount and, if used appropriately and in an integrated fashion with the strategic planning process, can serve both processes concurrently and produce a sufficiently robust LTRP. We leave it to the FEU senior management to determine how these funds may be best used to achieve this end.

6.4.6 Operations Support

The FEU project an annual operating and maintenance budget for the Operations Support department of $11.238 million in 2012 and $11.802 million in 2013, representing an increase of 14.1 percent over 2011 (forecast and approved), with an additional forecast increase of 5.0 percent in 2013 over 2012. Employees are forecast to increase by one (over 2011 approved) during 2012 and three during 2013. (Exhibit B-1, pp. 235-236)

The FEU state that cost escalations for Mainland in 2012 and 2013 are largely the result of labour and benefit escalation, codes and regulations and service standards and reliability. (Exhibit B-1, p. 238, table 5.3-53) They submit that codes and regulation costs related to required maintenance of aging emergency response equipment, gas detectors and communication towers result in cost escalations of $352 thousand in 2012 with an incremental $65 thousand in 2013. (Exhibit B-1, p. 238)

As a component of customer and stakeholder expectations, the FEU also request approval for an additional employee to be added to support growth in the business including new NGV and Biomethane initiatives at an incremental cost of $52 thousand. (Exhibit B-1, p. 239) Within the service standards and reliability area, the FEU also expect to incur additional costs for meter repairs and maintenance such as battery replacements to extend the life of their meters. Finally, the FEU propose to add an additional employee in 2013 for the purposes of procurement related to the long-term sustainment plan. The FEU plan to begin asset replacement activities related to the LTSP in 2012. The total cost for this additional employee will be $107 thousand. (Exhibit B-1, pp. 239-240)

Commission Determination

The Commission Panel accepts the requested increases in the Operations Support department for the test period. However, the Commission Panel is not convinced that the traditional gas business is growing at a rate to justify this incremental cost. The outcome of the Biomethane review and AES Inquiry may ultimately impact the treatment of the costs to support these programs in future revenue requirements applications.

6.4.7 Human Resources

The FEU point out that the overall goal of Human Resources is to ensure that the Companies' workforce has the skill level and capacity to achieve the business goals of the FEU both now and in the future. To deliver its services, the Human Resources function is separated into four areas: Corporate Human Resources, Employee Services, Employee Relations and Recruiting and Employee Development.

The Human Resources function has projected costs of $8.966 million in 2012 (+ 8.2 percent) and $9.382 million in 2013 (+ 4.6 percent). The current 70 employees are expected to increase by one for each of 2012 and 2013 for a total of 72.

The FEU request an additional $59 thousand to satisfy the requirements of Canadian Standards Association Z662 Annex "N" (related to pipeline integrity) and to ensure that the management of competencies is consistent, efficient and sustainable. The Companies note that approval of this funding will ensure governance functions in the competency management program, which is one of the building blocks for FEU's talent management processes.

With respect to demographic challenges, Human Resources requires an additional $225 thousand in O&M funds in 2012 to allow for additional levels of training and related expenses to meet business demands. In addition, another $59 thousand is requested for 2012 to deploy e-learning courses which have been developed over the past two years.

The FEU advise that starting in 2010, Human Resources began the process of defining departmental technical requirements which documented the Human Resources Information System Roadmap (HRIS) outlining the function's long term strategy for Information Technology. They submit that it will cost $29 thousand in 2012 to purchase additional licenses, servers and related maintenance to improve administration of processes. The FEU also request an additional $109 thousand in 2013 to cover the cost of an additional resource in the HR Information Technology group. This individual will support the implementation and sustainment of two new software programs. (Exhibit B-1, pp. 245-251)

Commission Determination

The Commission Panel considers the O&M expenditures requested for the Human Resources area to be acceptable. The impact of demographic change is significant and it is not unreasonable that the responsibility and cost for some of the training related to this will be included in this area. The funds being expended on Information Technology (IT) projects are an extension of projects which were begun earlier and likewise appear to be an effective use of resources. **The Commission Panel approves the Human Resources budget increases as requested**.

6.4.8 Information Technology

The FEU project an annual operating and maintenance budget for the IT department of $21.927 million in 2012 and $22.696 million in 2013, representing an increase of 6.9 percent over 2011 (forecast and approved), and an additional forecast increase of 3.5 percent in 2013 over 2012. Full time employees are forecast to increase above previously approved levels by eight in 2012 and one more in 2013. (Exhibit B-1, p. 221)

The FEU indicate that in 2010 the IT department had approximately $1.3 million lower O&M costs than approved due to variance in the areas of labour, consulting costs, and software. The labour cost savings amounted to $0.63 million even though the FEU had only one less employee than the approved number. The FEU project 2011 costs will be in line with the approved amounts, however, they also forecast to have two additional employees beyond the approved 2011 number. (Exhibit B-1, p. 223)

In the test period, the bulk of the requested increase in IT O&M costs relates to the service standards and reliability cost driver. For 2012, the FEU forecast an increase in FEI's service standards and reliability costs of $1.358 million with a further $0.475 million in 2013 due to IT contractual obligations, growth in staffing levels, and business-driven initiatives for IT projects. (Exhibit B-1, p. 224)

Staffing Level Growth

Amongst specific cost drivers, the FEU note that "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." (Exhibit B-1, p. 224)

In House Service Offering

The FEU also propose to bring back in-house a number of IT development and support functions in 2012 and 2013 which are currently conducted by vendor partners or external consultants in areas where it offers value for the customer. The FEU believe this change will reduce the loss of core knowledge and expertise and will lead to increased scalability and versatility of the internal team. The FEU later state that, in relation to bringing these services in house, the addition of six employees in 2012 and the one employee in 2013 will be required. (Exhibit B-1, p. 222-225, Exhibit B-1-3, p. 221)

Support Costs for Capital Projects

The FEU have calculated that 10.5 percent of the IT requirements are for O&M to effectively execute the planned capital expenditure. This is based on an analysis of 2010 actual costs and the 2011 IT Project Portfolio. Therefore, the FEU are forecasting IT O&M costs related to capital projects at $2.1 million in each of 2012 and 2013 (which is 10.5 percent of the planned $20 million of IT capital.) This is an increase in 2012 of $920 thousand from the 2011 approved level of $1.18 million. (Exhibit B-1, p. 225)

In 2010, the Commission approved capital expenditures of $16 million but actual capital expenditures only amounted to $12.418 million. (Exhibit B-1-4, p. 332, Table 6.2-1)

Commission Determination

The Commission Panel has a number of concerns with the IT O&M operating budget. These concerns relate to IT budgetary controls, the FEU's growth and moving IT in-house and are discussed below.

IT Budgetary Controls

In 2010, the IT department significantly over-budgeted both its O&M costs as well as its capital expenditures. The total unspent IT O&M budget for 2010 amounted to approximately $1.3 million or 7.3 percent of the department's total forecasted operating budget. While a number of 2010 IT O&M costs may be attributable to unanticipated events, the ability of the FEU to achieve a $630 thousand reduction in labour costs below the approved level despite having only one less employee than approved is a concern to the Commission Panel. The labour-related over-forecasted IT O&M expense of $630 thousand alone represents 3.4 percent of the department's forecasted operating budget. While costs such as training may have been avoidable, such considerations should have been incorporated into the budget for the 2010-2011 test period to ensure requested costs only reflected reasonably necessary costs. While the FEU's projected 2011 costs are in line with the approved staffing levels, the Commission Panel notes that the FEU also project to have two additional employees in 2011 beyond the approved numbers. The Panel would have expected the additional staff to drive up department costs resulting in budgetary overruns unless non-labour costs were significantly lower than forecast.

The Commission Panel accepts that a number of factors beyond the FEU's control may have led to the under spending on labour and non-labour IT costs in 2010 and 2011. **Accordingly, the Panel approves the FEU IT O&M budget, subject to the directives contained in this Decision.** But the Panel also reminds the FEU that a more fulsome explanation of the actual IT O&M costs, relative to budgeted costs, should be provided in future revenue requirements applications. This explanation should demonstrate that adequate budgetary controls exist to prevent the overstatement of future IT O&M costs.

The FEU's Growth

The FEU suggest that IT cost increases of $92 thousand in 2012 and an additional $12 thousand in 2013 are necessary due to the growth of the FEU with respect to new employees and additional applications, infrastructure and related security. The Commission Panel is concerned that the FEU traditional gas utility business is not experiencing significant customer growth and actual residential customer usage rates are in fact contracting. (Exhibit B-1, pp. 76, 91, 103) Given this trend towards lower usage and a flat customer base, the Commission Panel expects the FEU to identify ways to ensure future cost stability. The growth in IT O&M costs to "support the projected growth and maturation" of the FEU does not appear to reflect the Companies' economic realities. The Commission Panel is concerned that employee growth to support non-traditional business areas may be driving the growth in IT O&M costs, but that this factor has not been adequately factored into the overhead cost allocation mechanisms, given the high value of cost escalation within this department. While the TES overhead allocation component takes into account a charge for IT services, this charge has remained relatively constant at an amount of approximately $51,500 in each of 2012 and 2013. (Exhibit B-9-1, Attachment 78.1) The Commission Panel believes that the IT component of the overhead charge can be reasonably isolated and evaluated separately from other components of the overhead allocation based on the evidence in this proceeding. On this basis, the Commission Panel finds that the IT component of the overhead allocation to the TES deferral account should be addressed separately from the rest of the overhead charge, and is best evaluated within the IT department.

The Commission Panel is not persuaded by the evidence that these IT costs are related to the services received by traditional gas customers given the flat growth rate in customer load. Further, the Commission Panel does not believe that the flat IT systems charge included in the overhead allocation to the TES deferral account is sufficient given the IT O&M cost growth driven by TES offerings**. The FEU are directed to allocate this requested increase of $92 thousand in 2012 and $104 thousand in 2013 to the AES deferral account in addition to the Commission approved overhead allocation.**

<u>Moving IT In-House</u>

The FEU indicate that they plan to move certain IT services from external service providers, in-house, in areas where the transfer offers value to customers. The Commission Panel notes that the FEU forecast the cost of this move at $89 thousand in 2012 with an additional incremental amount of $40 thousand in 2013. While the FEU state that the benefit of such a change relates to the retention of knowledge, versatility and scalability, the Commission Panel is not convinced that the changeover will result in any needed improvement to IT operating quality. The FEU have not provided sufficient evidence to explain what inadequacy is currently being experienced with IT services provided by third party providers to justify increasing annual costs by $89 thousand in 2012 and by $129 thousand in 2013. Further, the Commission Panel questions what needed value is provided by moving IT services in house if no significant quality issues have been identified. If the third party service providers are able to perform these IT services adequately and at lower cost than the FEU, then the Commission Panel does not believe the evidence supports the requested cost increase. **Therefore, the Commission Panel does not approve the FEU's requests for $89 thousand in 2012 and $129 thousand in 2012 to move certain IT services in-house.**

6.4.9 Environment, Health and Safety

The Environment Health and Safety group (EH&S) comprises five areas:

-Environmental Affairs

-Occupational Health and Safety

-Public Safety Awareness

-Emergency Preparedness

-Business Continuity Planning

-Corporate Security

The FEU submit that they place a high priority on safe work practices and on minimizing the impact of their work on the natural environment.

The FEU have requested O&M costs of $2.893 million in 2012 (+10.6 percent) and $3.057 million in 2013 (+5.7 percent). The EH&S group expects there will be no addition to the number of employees during the test period.

Of the requested increase, an additional $50 thousand is stated to be required starting in 2012 to deliver environmental training to Operations employees to maintain compliance with Annex A of CSA Z662 Pipeline Standard. The FEU state that as part of their maintenance of an Environmental Health System that is compliant with ISO 14001 EMS Standard, they will be implementing an enhanced waste management tracking system in 2013. The cost of this program is $35 thousand and will allow logged hazardous wastes to be managed throughout their life cycles and archived in one place.

In support of business continuity, FEI plans to attain an expanded Disaster Recovery capacity to provide an alternate location from which first response employees can work. A total of $36 thousand is required in both 2011 and 2012 for the purchase of licenses, wiring and equipment related to telephony. In 2013 a further $50 thousand is required for materials to enable data access expansion to the Disaster Recovery site. Alternate physical work areas in existing FEI offices in the Lower Mainland will also be equipped to manage daily operations requirements outside of the regular Surrey operations site. (Exhibit B-1, pp. 251-256)

Commission Determination

The Commission Panel accepts the need for environmental training as outlined in the Application. However, the Panel is less convinced that it is necessary to spend $50 thousand annually to provide the training on an ongoing basis. **Accordingly, FEI is directed for future revenue requirements to determine potential alternatives for the delivery of this program and potentially integrate it with other training initiatives.**

The Commission Panel is of the view that the Disaster Recovery initiative is reasonable. At a minor cost, the FEI is providing insurance to ensure it can continue to operate in the event of a disaster. **The Commission Panel approves all incremental cost requests for the EH&S group**.

6.4.10 Facilities

The FEU project an annual operating and maintenance budget for the Facilities Department of $7.893 million in 2012 and $6.892 million in 2013, representing an increase of 0.9 percent over 2011 (forecast and approved), and a forecast decrease of 12.7 percent in 2013 over 2012. Full time employees are forecast to increase by one during the test period. (Exhibit B-1, p. 242)

Commission Determination

The Commission Panel has reviewed the budget for the Facilities department, and subject to adjustments made elsewhere in this Decision, approves the requested spending in the test period.

6.4.11 Finance and Regulatory Affairs

The FEU project an annual operating and maintenance budget for the Finance and Regulatory Affairs Department of $11.360 million in 2012 and $11.688 million in 2013, representing an increase of 9.9 percent over 2011 (forecast and approved), and an additional forecast increase of 2.9 percent in 2013 over 2012. FTEs are not forecast to change during the test period.
(Exhibit B-1-3, pp. 258-259)

Of the requested increase in Finance and Regulatory Affairs O&M costs for 2012, the FEU identified customer and stakeholder expectations as the cost driver for $457 thousand in 2012 incremental costs within FEI and $89 thousand in incremental costs within FEVI. The FEU attribute the remainder of the increase to labour and inflation within FEI and FEVI. The FEU tie the entire increase in costs in 2013 to FEI labour inflation and benefits. (Exhibit B-1-3, pp. 260-261)

Within customer and stakeholder expectations, the FEU state that forecast 2012 cost increases were a result of higher BCUC quarterly assessments of $300 thousand within FEI and $50 thousand within FEVI, higher audit fees resulting from the planned adoption of International Financial Reporting Standards (IFRS) (given that IFRS doesn't allow for rate regulated accounting) amounting to $67 thousand within FEI and $29 thousand within FEVI and newly required government emissions reporting totalling $90 thousand within FEI and $10 thousand within FEVI. (Exhibit B-1-3, pp. 260-261)

In the FEU's July Evidentiary Update, the estimated annual ongoing audit costs were reduced by $206 thousand. This was due to the United States Generally Accepted Accounting Principles' (US GAAP) Decision[10] allowing the FEU's adoption of US GAAP for regulatory purposes (as US GAAP allows for regulatory accounting, subject to the elimination of the Utilities' intention to perform a US Securities Exchange Commission (SEC) listing). (Exhibit B-11, p. 2)

Commission Determination

The Commission Panel has reviewed the FEU's forecast O&M for Finance and Regulatory Affairs for the test period, as amended, and approves the amended forecast costs as consistent with Commission Order G-117-11.

6.4.12 Corporate and Shared Services

The FEU have described how costs are allocated between related but separate entities. Corporate services are provided by Fortis Inc. and FortisBC Holdings Inc. (FHI) to the FEU. The FEU also share costs amongst each other and with FortisBC Inc. (Exhibit B-1, pp. 276-277)

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[10] In the Matter of An Application by the FortisBC Utilities (comprising of FortisBC Inc., Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.) for Approval to Adopt US Generally Accepted Accounting Principles effective January 1, 2012; Decision and Order G-117-11 dated July 7, 2011 (US GAAP Decision)

The FEU submit that the relationship between the FEU, FHI and FortisBC Inc. is generally unchanged from the time of filing of the 2010/2011 Revenue Requirements Applications (RRAs) for FEI, FEVI and FEW and that the approach and methodologies used for corporate and shared services are the same as those reviewed and reported upon by KPMG for the 2010/2011 FEI RRA. The FEU further note that the methodologies for shared services across the Companies are similar to those in use in the 2010/2011 RRA and reflect the same cost drivers. The FEU also clarify that the Shared Services Agreements between FEI and FEVI and FEI and FEW are unchanged from the agreements filed in the 2010/2011 FEI and FEVI RRAs and notes that that the Companies have made an overhead allocation of $0.5M to TES as a separate component of cost allocation. (FEU Final Submission, p. 81)

The FEU have also submitted evidence of a plan to grow the TES portfolio aggressively to $250 million, and identified that TES is important to the FEU's future. (Exhibit B-1, Appendix G, p. 2, T2: 195)

While CEC makes no submission on the corporate or shared services studies, it is concerned with the growth in corporate and shared services costs, particularly in 2012.

The CEC submits that management can improve productivity by one percent or more and encourages the Commission to consider setting rates incorporating this assumption. (CEC Reply Submission, p. 35)

Commission Determination

The Commission Panel notes that there appears to be little change to the interactions between the FEU and their related entities. However, the Commission Panel is cognizant of the fact that the FEU have plans to expand their TES offerings in the future. We believe that this will require the use of certain resources of the FEU and other related entities, some of which are not regulated. As the Corporate and Shared Service Agreements address costs of these regulated and non-regulated entities and apportion an allocated amount to the FEU, the Commission Panel believes that the development of TES will impact the mix of cost allocations amongst not only the FEU, but potentially amongst service offerings of the FEU. **For that reason, the Commission Panel directs the FEU to update both the Corporate and Shared Service Agreements for inclusion in their next revenue requirements application. Further, the Commission Panel directs the FEU to break activities of the FEU entities into two, distinct parts:**

- **Those of traditional gas operations, and**
- **Those of TES offerings**

so that costs attributable to each entity of the FEU can be clearly broken down by their TES component.

The Commission Panel generally supports the concept of encouraging productivity amongst the FEU. However, as cost allocations are designed for the purpose of cost distributions, the Panel does not believe that imposing a productivity reduction in the cost allocation is appropriate. Rather, the Commission believes that encouraging productivity amongst actual cost centers is a more effective means to incent the FEU to find methods to optimize customer value.

6.5 Other Operational Cost Issues

6.5.1 Community Expenditures

The FEU have historically provided community involvement funding. Past and projected funding levels for FEI and FEVI are as set out below:

Table 6.3
Community Involvement Spending

	2009		**2010**		**2011 YTD May**		**2012**	**2013**
Utility	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Budget**	**Budget**
FEI	$370,267	426,000	527,133	426,000	134,189	426,000	430,000	437,000
FEVI	51,944	70,000	87,559	70,000	39,943	70,000	71,600	73,300
Total	**422,211**	**496,000**	**614,692**	**496,000**	**174,132**	**496,000**	**501,600**	**510,300**

(Source: Exhibit B-9, BCUC IR 1.61.1)

The FEU assert that the key influences and cost drivers of their community involvement spending are quite varied. In all cases, the FEU believe the objectives of these investments in the communities the FEU serve and operate include:

- Creating community partnerships that improve both their ability to work in these communities and the effectiveness of those activities;
- Improving the pride that FEU employees take in working for the FEU and thus increasing productivity and attracting high quality employees;
- Increasing or maintaining the pride and trust that customers have in the FEU's business through knowing that the FEU are actively engaged in the improvement of the communities they live in; and
- Sharing information about the energy services FEU offer and activities FEU conduct in the communities they serve, which can include information about programs and safety.

(Exhibit B-17, BCUC IR 2.28.1)

The CEC submits that a number of "good corporate citizen" activities of the FEU have better positioned the Companies to deliver benefits to their customers than had none of the activities been under-taken. The CEC submits, however, that the FEU have a challenge before them to realize this potential. Although the CEC generally accepts the FEU's comments on the value of improving relationships through investments in community, it expects to see commitments to and achievements of improved productivity and cost effectiveness in return. CEC is of the view that evidence of a reciprocal benefit is lacking. (CEC Final Submission, p. 45)

BCOAPO takes the position that community investment costs do not simply confer benefits on the community, but also on the shareholder by increasing goodwill, and that the shareholder should bear a portion of these costs. (BCOAPO Final Submission pp. 29-32)

Commission Determination

The Commission Panel acknowledges that the Community Involvement Spending recipients appear to represent worthy causes. However, the Commission Panel finds that there are benefits to the shareholder that accrue from the FEU's community involvement spending. Included among these are the following:

- An increase in the goodwill of the Company or Companies that may be reflected in the share value or value if sold;
- The use of community involvement to differentiate the FEU and provide it with a competitive advantage over other energy providers; and
- The ability for the FEU to promote activities outside their traditional monopoly business role, expanding the scope and revenue base of the companies benefiting the shareholder, but not necessarily benefitting the traditional company ratepayer.

The Commission is concerned that with all of the costs of Community Involvement Spending being borne by the ratepayer, the incentive for FEU to clearly focus on those activities that will help achieve their objectives is diminished. The Commission Panel is of the view that greater discipline will occur if the shareholder bears some of the community involvement costs. This combined with the finding that benefits accrue to the shareholder as a result of this involvement are why the Panel has determined it appropriate to share costs between the shareholder and the ratepayer. **Accordingly, the Commission Panel directs that all Community Involvement Spending will be allocated 50 percent to the ratepayer and 50 percent to the shareholder.**

6.5.2 Expenditures on the Olympic Cauldron

FEI paid $3.21 million to fund the Olympic Cauldron, located in the Jack Poole Plaza in downtown Vancouver, in 2009. This cost was placed into rate base (in Asset Class 48600 – Tools and Equipment) in 2009 but did not affect rates at that time as rate base for rate setting purposes was determined by formula pursuant to the PBR established as part of the Negotiated Settlement Agreement for 2010 and 2011. As of 2012, the Cauldron has been included in rate base for rate setting purposes at its net book value of $2.889 million. The FEU propose to recover this cost from ratepayers over the Cauldron's estimated remaining useful life of 18 years. The FEU estimates the revenue requirements impact to be $350,000 per year for the test period.

By agreement with the owner of the Jack Poole Plaza, BC Pavilion Corporation, FEI is to retain ownership of the Cauldron and has a license to allow the Cauldron to remain in the Plaza for 20 years, with renewal rights for a further 40 years. BC Pavilion Corporation is responsible to maintain the Cauldron.

The cost to light the Cauldron is approximately $1,000 per hour. This cost is to be borne by BC Pavilion Corporation and may also be borne on occasion by FEI, as part of its community investment budget. (Exhibit B-9, BCUC IR 1.5.2, Attachment 5.2, Exhibit B-17, BCUC IR 2.3.1)
The FEU take the position that the Cauldron is a "unique asset" which has an intrinsic value associated with "good corporate citizenship" and is also of value in that it will facilitate community acceptance of the FEU's ongoing operations. (FEU Final Argument, p. 161, Exhibit B-17, BCUC IR 2.3.1) The FEU take the further position that "the reputational impacts associated with good corporate citizenship flow to customers of the operating utilities." The FEU argue that because, in their submission, the benefits of the Cauldron flow to the FEU's customers, the cost represented a prudent expenditure and the FEU's customers should bear 100 per cent of cost of the Cauldron, along with the additional cost relating to the rate base rate of return to the shareholder, which they argue is the shareholder's benefit. (FEU Final Argument, pp. 162, 164; FEU Reply, p. 49)

Used and Useful

The FEU also argue that the Cauldron is a “used and useful” rate base asset as it is used from time to time for community events and, when used, consumes gas. The FEU further argue that when the Cauldron consumes gas, this puts load on the system and generates revenues which in turn benefits ratepayers. The FEU also argue that the Cauldron is “used and useful” in the sense that it symbolizes the FEU’s community investment as a “lasting legacy.” (FEU Final Argument, p. 163)

The BCOAPO “strongly opposes” the inclusion of the Cauldron in rate base. In its submission, the Cauldron is not used or useful. The BCOAPO notes that Mr. Walker agreed with the definition of “used and useful” extracted from a book entitled “The Regulation of Public Utilities Theory and Practice” - Charles F. Phillips Jr. Robert G. Brown Professor of Economics Washington and Lee University 1988 Public Utilities Reports Inc. Arlington, Virginia which was put to him in cross-examination. (T2: 238) That definition was that to be used and useful the Commission must determine whether a utility investment is “needed and economically desirable.” BCOAPO argues that the Cauldron is neither needed nor economically desirable for ratepayers from a service standpoint. BCOAPO notes that the Cauldron is not a distribution asset and submits that it does not add any meaningful value to ratepayers. BCOAPO argues that the fact that the Cauldron adds load to the system by periodically burning natural gas into the atmosphere does not make it used and useful and likens it to a leaky pipe. Similarly, BCOAPO argues it would not be acceptable for the Utilities to sponsor a neighbourhood’s gas fireplaces and include them in rate base, even if it increased relations with that community.

BCOAPO further submits that “[t]he Utilities could not provide any evidence that the ...Cauldron has improved community acceptance of projects...” and notes that the projects cited by the FEU in their testimony as examples both occurred prior to the Olympics. (BCOAPO Final Argument, p. 31)

The FEU argue that the broader definition of used and useful put to Mr. Walker requiring an asset to be “economically desirable” should be rejected and that assets should be assessed in terms of their use and usefulness in the provision of utility service. (FEU Reply, p. 48) The FEU further submit that “[a]s is the case generally with community investments, it is difficult, if not impossible, to show one-to-one relationships between an investment and an acceptance of a project. This does not mean that such investments do not have that effect.” (FEU Reply, pp. 48-49)

Retail Markets Downstream of the Meter

The FEU note that the Commission’s “Retail Markets Downstream of the Meter” (RMDM) Guidelines were raised during the Oral Hearing in the context of the Cauldron but submit that they are not relevant. The Guidelines state: “[t]he Commission has jurisdiction to prohibit a public utility from participating in retail markets downstream of the meter if prohibition is the only reasonable and effective means by which the Commission can mitigate or alleviate any negative effects on ratepayers.” The FEU argue that the Cauldron is a unique asset for which there is no retail market and that the RMDM Guidelines are more applicable to a utility participating in retail activities such as furnace repair.

BCOAPO submits that, while it is true that there is no retail market for symbolic ceremonial flames, the principles of RMDM Guidelines still apply and the Commission should prohibit the utility from owning downstream assets which may harm ratepayers. BCOAPO submits that the Cauldron is an appropriate case to prohibit recovery from rates. BCOAPO further submits that “[t]he Utilities have not provided any authority to support their assertion that a unique, “once in a lifetime opportunity” is a reason to include an asset in rate base and BCOAPO sees no rational reason to do so.” (BCOAPO Final Submission, p. 31)

Commission Panel Determination

The Commission Panel agrees that the Cauldron is “unique” and that it was a project undertaken by the FEU as part of its development of good relationships in the communities in which it does business. However, the Commission Panel is not persuaded that the Cauldron is “used and useful” under any relevant test. The Cauldron is not a distribution asset and is neither used nor useful in the provision of utility service. The Commission therefore finds that the Cauldron is not a distribution asset providing service to FEI ratepayers. **The Commission Panel directs that the cost**

of the Cauldron be removed from FEI's rate base.

The Commission Panel does not accept that the only benefit to the shareholder of community investment is the prospect of a return on its investment. The Commission Panel notes that "goodwill" is an intangible asset which provides value to a corporation and activities which create goodwill provide benefit to the shareholder of that corporation. **The Commission Panel finds that the FEU's shareholder has received benefit from funding the Cauldron.**

While the Cauldron is not an approved capital asset, the Commission Panel does accept that it is a form of Community Involvement Spending (which has also been justified by FEU on the basis that Community Involvement Spending creates goodwill and builds good relationships in communities which facilitates FEU's work in these communities). While the Commission Panel recognizes that the Olympics were a unique event, it does not consider it appropriate for ratepayers to absorb all of the contribution costs of the Cauldron.

The Commission Panel approves one half, or $1.4445 million in costs for the Cauldron in FEI's 2012 O&M expenses. The balance is to be absorbed by the shareholder.

6.5.3 Capitalized Overhead

In the Application, the FEU propose to maintain their capitalized overhead rate consistently at 14 percent. This rate was agreed to in the 2010-2011 Negotiated Settlement Agreement for both FEI and FEVI and approved for FEI (Fort Nelson) and FEW. (FEU Final Submission, p. 81) The FEU note that the proposed capitalized overhead rate remains higher than the rates determined in a recent study dated June 10, 2009, and prepared by KPMG. This study was done in preparation for the (then proposed) regulatory adoption of IFRS in 2011 and recommended an overhead capitalization rate of 8.17 percent for the FEU and 5.22 percent for FEVI. (2010-2011 Terasen Gas Inc. Revenue Requirements Application, Appendix H-3)

However, as noted earlier, the FEU have since abandoned plans to adopt IFRS in either 2011 or 2012 and have received Commission approval in the US GAAP Decision to adopt US GAAP for regulatory purposes in 2012-2014, under which capitalized overhead treatment is not noted as a variance from the FEU's current treatment (under Canadian Generally Accepted Accounting Principles).

CEC submits that capitalized overhead rates of 15 percent would not be inappropriate. (CEC Final Submission, p. 34)

Commission Determination

The Commission Panel is of the view that the customers who benefit from expenditures should be those who bear the costs of the expenditures wherever possible. To defer additional costs to the future would, in the Commission's opinion, pose a greater risk of intergenerational inequity as the capitalized overhead allocation is an estimate, and not a precise measure, of capital costs deferred to the future. Accordingly, the Commission does not agree that increasing the capitalized overhead rate to 15 percent is reasonable in this test period. **Given the various changes in accounting standards and the desired expansion of the FEU's customer offerings and new business activities, the Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application.**

6.6 Depreciation and Capitalization

6.6.1 Depreciation Rates

The FEU propose to adopt new depreciation rates as recommended in a Depreciation Study performed by their independent expert, Gannett Fleming. (FEU Final Submission, p. 83) That study recommends a general overall increase in depreciation rates which the FEU note contributes materially to the proposed delivery rate increases in the 2012 and 2013 test period. (FEU Final Submission, p. 83)

The FEU submit that depreciation rates are set to provide a reasonable assurance of the recovery of invested capital over the useful lives of the assets from the customers who take service. (FEU Final Submission, p. 83) The FEU note that, as a result of reviewing various characteristics of existing assets, Gannett Fleming has concluded that the FEU's total existing rates are not sufficient to accomplish this recovery. Gannett Fleming has therefore recommended accelerating depreciation rates, which will result in an overall increase in depreciation expense for the FEU of approximately $4.6 million. (Exhibit B-1, p. 283)

BCOAPO takes no issue with respect to Gannett Fleming's Depreciation Study. However, it expresses concern with historical depreciation results during the 2007-2009 PBR period. BCOAPO supports rigorous and regular reporting to the Commission and stakeholders every three years regarding asset depreciation and other metrics of asset usage versus recovery of costs from customers. However, BCOAPO suggests that under certain conditions, it may be appropriate to establish a deferral account to capture differences between actual and forecast depreciation. BCOAPO also supports some smoothing mechanism to mitigate short-term rate stability issues where depreciation rates are a significant driver of increased rates. (BCOAPO Final Submission, pp. 18-19)

CEC submits that the Commission can rely on Gannett Fleming Depreciation Study. In addition, CEC states that it would be appropriate to set rates based on those results, subject to certain conditions. These include a deferral mechanism to capture differences between forecast and actual depreciation, as well as some form of productivity improvement factor. (CEC Final Submission, pp. 35-36)

The Large Industrial Users Group (LIUG) does not dispute the proposed depreciation rates, however, it submits that a phased-in approach should be considered for the changes in depreciation rates. (LIUG Final Submission, p. 5)

The FEU submit that a deferral account to capture depreciation variances between forecast and actual amounts is unnecessary as rate base is trued up at the beginning of each test period so the impact in each test period is only short-term. The FEU also note that actual variances since the PBR have been minor. Further, the Companies submit that if a deferral account of this nature was created, a tax variance account would also be needed to capture the differences between depreciation for financial accounting purposes and capital cost allowance (CCA) for tax purposes.

The FEU would prefer to calculate depreciation expense on an opening plant in service balance rather than using such a deferral mechanism. (FEU Reply Submission, p. 29)

The FEU also submit that depreciation variances during the PBR resulted from the formula mechanism used to calculate depreciation and the results were as intended and expected. Further, the FEU indicate that the rates set by PBR were determined by the Commission to be just and reasonable and the FEU do not believe it is appropriate to set any productivity factor for the test period based on the past PBR mechanism. (FEU Reply Submission, pp. 30-31)

Commission Determination

The Commission Panel accepts Gannett Fleming's Depreciation Study and approves the changes

in depreciation rates recommended by that study as it is satisfied that those rates best match the actual service lives of assets with the period of benefit to ratepayers at this time. We do not believe that deferring or phasing-in the changes to depreciation rates would be in the best interest of ratepayers, especially in light of the current price of natural gas. This strategy would only serve to postpone the inevitable.

The Commission Panel shares the concerns of Interveners regarding some depreciation outcomes of the PBR period. In spite of this, we accept that no mechanism designed to penalize FEU should be imposed as the Utilities did comply with the approved PBR agreement. However, in the design of any future PBR mechanism, the Commission Panel recommends that the parties take into account the potential impact of asset usage and deprecation. We believe that the variance between forecast and actual depreciation should be attributed to ratepayers for this test period. The FEU describe these variances as "short term in their nature." However, the Panel does not agree with this characterization. These variances are permanent, do not reverse in the future and can occur in successive test periods. **Therefore, the Commission Panel directs that a deferral account be established to capture the variances between forecast depreciation and actual depreciation in the test period as well as the directly attributable variance between forecast tax impacts and actual tax impacts for the test period only.**

While calculating depreciation on an opening plant in service may reduce the likelihood of such variances from occurring, the Commission Panel is not convinced that such a method will completely absorb all potential variances between forecast and actual results over a two year test period. **The FEU are directed to report the annual additions to this deferral account by asset class in a report to be included with the Utilities' Annual Regulatory Report.** The report is to include a breakdown of each addition by depreciation amount and tax effect subtotalling to an amount for each deferral. The total of deferrals in this report shall agree to annual deferrals made to the account. For each asset resulting in a deferral, the asset shall be further broken down by asset class components, indicating the deferred depreciation and deferred tax impact of each component (by asset class). The tax amounts shall include a notation of the CCA class to which they relate as well as the CCA rate for that class.

6.6.2 Negative Salvage Value

The FEU request a change to the practice of collecting salvage costs from ratepayers. These are the costs incurred at the end of an asset's useful life in order to take the asset out of service. In some instances, the Utilities experience positive salvage recoveries through the sale of assets no longer useable by the Utilities, but generally, the salvage of assets is done at a cost resulting in a negative salvage value. (Exhibit B-1, Appendix E-2)

The FEU identify four possible methods to recover negative salvage values from ratepayers. These are: the traditional approach, a pay-as-you-go approach, Asset Retirement Obligation (ARO) style accounting and a Hybrid approach. The Companies seek approval to adopt the traditional approach during the test period for all retirement obligations that are not AROs as defined by Generally Accepted Accounting Principles. Under the proposed traditional approach, the Utilities seek the salvage rates estimated within the Gannett Fleming Depreciation Study. Currently, the FEU collect salvage provisions on a "pay-as-you-go" basis. The FEU submit this method is subject to volatility as actual retirement costs are estimated to increase as the assets near the end of their average useful lives, which results in tomorrow's ratepayers paying to retire assets used today. Further, the FEU argue that the traditional negative salvage approach is a common, widely used practice amongst comparable utilities across the country and is also the method of accounting for salvage costs generally accepted for use in the United States within the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts. (Exhibit B-1, Appendix E-2)

The FEU believe that using the traditional approach to negative salvage will not only benefit ratepayers by avoiding intergenerational equity issues, but will add transparency to retirement provisions and offer rate stability and administrative efficiency. (FEU Final Submission, p. 89)
In estimating salvage provisions, the FEU note that under general circumstances, the majority of

the Companies’ retired assets are abandonments and are separate from the installation of new assets. However, in cases where assets are retired and replaced, the Utilities submit that they will be in a position to allocate costs reasonably as between the asset replacement and the asset retirement. (Exhibit B-9, BCUC IR 1.137.3 - 1.137.6)

The FEU intend to accumulate negative salvage amounts in a rate base deferral account which will offset the assets to which they relate until such time as the salvage cost is actually incurred, when that cost will become part of rate base. The Companies argue that this early collection of retirement costs will give ratepayers adequate credit for the fact that cash is collected before its usage as it will result in an initial overall reduction to the Utilities’ rate base. The FEU also offer to report details of the amounts accumulated in the negative salvage account to provide transparency. (Exhibit B-1, Appendix E-2)

BCOAPO accepts the FEU’s proposed treatment of negative salvage. However it submits that there is a risk of over or under collection. It agrees that the annual reviews are important to examine negative salvage but notes that the Utilities are not at risk for any variance due to the forecast of asset retirement costs. BCOAPO submits that it is strongly incumbent on the Utilities to minimize any removal and abandonment costs and maximize positive salvage amounts. (BCOAPO Final Submission, pp. 20-21)

CEC supports the FEU’s proposed use of the traditional method to account for negative salvage costs and supports treating the net amount as a component of rate base. However, CEC also notes that the impact of negative salvage on rates during the test period is significant and believes a phased in approach should be considered. (CEC Final Submission, pp. 36-37)

Commission Determination

The Commission Panel accepts the FEU’s proposed application of the traditional method of providing negative salvage in rates during the test period. Using a “pay as you go system” to recover salvage costs could see ratepayers of tomorrow paying higher prices to retire assets which were used to the benefit of today's ratepayers. Further the Commission Panel also does not believe a phased in approach is appropriate. In our view, such treatment will only further defer costs of today for payment by future ratepayers and, given current fuel prices, such treatment does not appear warranted.

While net negative salvage rates are an estimate, the Commission Panel accepts that the rates are based on the recommendations of an independent expert. The Panel also accepts that net negative salvage is a widely used utility practice in Canada and is within the recommended accounting practices of FERC.

In addition, the Commission Panel accepts that the Companies have established a reasonable methodology to allocate costs between retirement and replacement of assets to ensure that these costs are properly recognized. However, we note that the standard retirement practice amongst most of FEU's asset groups does not involve asset replacements.

By adopting net negative salvage, the Commission Panel notes that the FEU will initially collect cash from ratepayers in excess of any actual salvage costs being incurred in the test period. The Commission Panel agrees with the FEU's proposal to treat the total collected negative salvage amounts, net of actual salvage costs, as a rate base credit account. The result will be a reduction in the FEU's overall rate base and ratepayers will benefit from such a reduction. However, the Panel believes that this net negative salvage account should be tracked and reported separately from plant in service to ensure maximum transparency. **Therefore, the Commission Panel directs the FEU to establish a rate base credit account to tabulate the total net negative salvage provisions less actual salvage costs. The Panel does not approve the presentation of the net negative salvage provision as a component of plant-in-service within the Utilities' assets.**

The Commission Panel agrees with BCOAPO that despite the use of negative salvage provisions, the FEU must make every reasonable effort to maximize positive salvage amounts and minimize removal or abandonment costs incurred upon asset retirement. **The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications.** Actual results of the past test period should be included in these applications.

In addition, the FEU are directed to provide annual reports to the Commission, of total accumulations, by asset class, of the following:

- **i) total salvage provision for the period,**
- **ii) total salvage expenditures,**
- **iii) a description of the total value of the asset rate base retired by asset class,**
- **iv) descriptions of the most common methods of retirement used during the period,**
- **v) the annual and cumulative to date (starting in 2012) actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired, and a comparison of how that rate compares to the rate recommended in the prior depreciation study,**
- **vi) a general description of any major trends or retirements that have occurred in the year (i.e. a specific type of pipe or type of meter that required a significant retirement), and**
- **vii) an update of trends, any alternative retirement methodologies not being used by the FEU and the future outlook of retirement procedures for each asset class including a description of how any changes in methodologies or available technologies could affect retirement costs.**

6.6.3 Asset Losses

In the 2010 and 2011 Revenue Requirements Application, the depreciation rates included in the Depreciation Study which formed part of that Application include a provision for recovery of unrecognized loss balances that accumulated prior to 2010. (FEU Final Submission, p. 98) The FEU note that 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. (Exhibit B-1, Appendix E-3)

The FEU submit that these losses (which represent unrecovered depreciation) should be fully recovered from ratepayers through current depreciation rates as the asset losses relate to prudently obtained assets that are being fully consumed in utility service, and the losses are the expected by-product of the group depreciation methodology employed. The FEU note that recovery of such losses is consistent with the Commission's Uniform System of Accounts, and past Commission determinations, as well as accepted practice in other jurisdictions. (FEU Final Submission, p. 98)

The FEU presented a graph demonstrating asset losses and gains for the Asset Mains category. They submit this document demonstrates that the Utilities expect to realize gains within certain asset classes towards the end of an asset class' average service life. The Companies explain that over the asset class' service life, the total retirement gains and losses are expected to net out to zero. (FEU Final Submission, pp. 103-104, Exhibit B-17, BCUC IR 2.74.13)

CEC submits that the asset losses represent costs for assets which customers have used (or were to use) for an expected life and therefore the amounts are recoverable from customers. However, CEC would like to see recovery of the losses over a 20-year period, to align with the expected service life of the relevant assets. CEC also encourages the Commission to consider a phased-in approach to allow for a longer period of collection of these amounts. (CEC Final Submission, pp. 37-38)

BCOAPO questions the Utilities' rationale for determining that asset losses on today's group of assets will be offset by future gains on these group assets as they reach the end of their service lives. BCOAPO points out that assets will consistently be added and will incur new losses, and as a result, ratepayers will never realize these gains. (BCOAPO Final Submission, pp. 23-24)

Commission Determination

The Commission Panel finds that the particular asset losses at issue in this Application should be recovered from ratepayers. However, the Panel notes that the assessment in this Proceeding is limited to the facts relating to this Application The Commission Panel does not, through this Decision, conclude that a utility is entitled to fully recover its investment of its plant in-service capital from ratepayers irrespective of management decisions made after those assets were placed into service. While certain asset losses may be an expected component of group depreciation practices, the Panel notes that a utility still has a responsibility to ratepayers for asset management beyond making prudent asset purchases. For example, assets require ongoing maintenance and repair in order to achieve their prudently intended value in use and the Commission Panel believes that a utility is responsible to ensure that assets are, at a minimum,

- prudently maintained; and
- used appropriately in operations.

Failure to prudently maintain and/or use assets appropriately could affect such assets' useful lives, and in such cases, the utility should bear responsibility. In other words, a shortened useful life in such circumstances will result in asset losses upon retirement that will likely not be recoverable from ratepayers. The Panel believes that these considerations are especially important during a PBR period where changes in maintenance schedules or pressure to minimize repair costs could have a direct negative impact on the service life of an asset. As such, the determination of asset losses can only be made on a case by case basis after examining the relevant evidence.

The Commission Panel also reminds the Utilities that while the asset loss review process may have taken a test period to resolve; these asset losses are significant in value and are complex in nature**.** **The Commission Panel directs the Utilities in the future to fully and transparently disclose the nature and amount of all assets or amounts included in their plant in service account that are being depreciated into rates but are not in use, or are not expected to be in use in the test periods, whether due to retirement or for other reasons.** The Commission Panel believes that these matters should be included and explained in applications and should not need to be identified through the IR process.

The Commission Panel notes that in this case a number of factors resulted in the Asset Losses and there was no evidence of asset misuse by the Utilities. **Therefore, the Panel directs that the Asset Losses be recovered from ratepayers, as proposed, in current depreciation rates.**

However, like the BCOAPO, the Panel does not necessarily accept the rationale that the Utilities will likely experience gains at a future point in time. We are of the view that gains will only occur if assets last beyond their expected useful lives. In our view, these "gains" are better characterized as "deferred asset replacements" due to the continued use of assets after they have been fully depreciated.

While losses of this nature may be a part of group asset depreciation, the Commission Panel directs the Utility to disclose specific information in future filings with the Commission. The disclosures should include the following:

1) **Future revenue requirements applications shall include details of actual asset losses, by asset class, for the past 10 years. They shall also include a forecast of losses, by asset class, for the remaining asset class, unadjusted for capital additions expected to occur outside the test period. As asset losses are expected under group depreciation, the Commission Panel believes that a projection of these losses should be readily determinable and should directly tie into depreciation forecasting methodology. When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates.**
2) **Future revenue requirements applications shall detail efforts made to minimize early asset retirements and to demonstrate how the utility intends to maximize the value of assets in use. As group depreciation methodology determines assets' useful lives on an average basis, the Commission Panel expects that at least some of the assets should be expected to last longer than their estimated useful lives. The Utilities shall describe the steps taken to determine which assets these might be and how the Utilities intend to identify, maintain and repair such assets. Furthermore, this process should incorporate capital asset maintenance plans to demonstrate how the value of assets in use is to be maximized such that assets are not just replaced, on a blanket basis, at the end of the assets' average service life.**

6.7 Rate Base

6.7.1 Mains Extensions

The Shawnigan Lake Road and West Coast Road FEVI mains extensions installed in 2009 have cost overruns of 176 percent and 53 percent, respectively. As of May 31, 2011, no customers have attached to the West Coast Road main extension and the Shawnigan Lake Road customer attachments were lower than forecast. (Exhibit B-9-1, BCUC IR 1.100.1, Attachment) Issues arising from this are whether the expenditure should be considered prudent and whether the main extension can be described as used and useful.

Prudency

The FEU submit that that the Shawnigan Lake Road and West Coast Road extensions were prudent investments, because FEVI's decision to undertake the extensions was based on the Commission-approved Main Extension (MX) Test and the information available at the time. (FEU Final Submission, pp. 164-165) In addition, the FEU state that the issues with the assumptions used in the MX Test, including the economic downturn that stalled development and the use of average costing as opposed to manual cost estimating, are only apparent with hindsight. (FEU Final Submission, p. 166)

CEC supports the FEU view that the Shawnigan Lake Road and West Coast Road main extension expenditures were prudent. (CEC Final Submission, p. 45) No other Interveners commented on this issue.

The Commission Panel rejects the Companies' assertion that the Shawnigan Lake Road and West Coast Road mains extensions were prudent investments because FEVI's decision was based on the Commission-approved MX Test. The Commission Panel notes that there are no statements or directives in the 2007 System Extension Decision[11] that exclude mains extensions from prudency or impairment reviews. Under cross examination, Mr. Thomson concurred with this interpretation of the 2007 System Extension Decision. (T4: 508)

Given that a little more than 2 years have passed since these extensions were constructed, the Panel agrees with the FEU that it is too soon to determine if they are economic. Therefore, the Panel makes no determination as to the prudency of the Shawnigan Lake Road and West Coast Road mains extensions. This does not preclude the possibility of a prudency review at a later date.

<u>“Used and Useful”</u>

The FEU submit that the Shawnigan Lake and West Coast Road main extensions are “used and useful” and should be included in rate base because Shawnigan Lake is in use and West Coast Road is expected to be used (FEU Final Submission, pp. 167, 172) They also state that the physical capacity to provide service and the reasonable expectation that customers will be connected to it in the near term should be the measure for “used and useful,” not the flow of gas at a given point in time. (FEU Final Submission, p. 168)

Commission Determination

The Commission Panel notes that under Section 9.1(b) of the FEVI General Terms and Conditions (GT&C), customers who have not consumed gas within one year after installation of the service line to the customer’s premises may be charged for the cost of the service line and meter set. Therefore, the Panel finds that a reasonable timeframe for the first customer to connect to a main and begin consuming gas is one year after construction of the main extension is completed.

The Shawnigan Lake customer attachments are lower than forecast, but customers have connected

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[11] In the Matter of An Application by Terasen Gas Inc. (TGI) and Terasen Gas Vancouver Island (TGVI) jointly the Companies for Approval to Amend Their System Extension and Connection Policies; Decision and Order G-152-07 dated December 6, 2007 (2007 System Extension Decision)

to the extension and are taking service. Therefore, the Panel considers the Shawnigan Lake extension used and useful. **Given that no customers have attached to the West Coast Road extension since construction was complete on June 1, 2009, the Commission Panel determines that it is not "used and useful." Accordingly, the Panel directs FEU to place the $401,092 cost of the extension and all operating, maintenance and depreciation costs in an interest bearing non-rate base deferral account until the first customer connects to the main and consumes gas.**

The West Coast Road extension is not the only high cost main extension that has no customer connections. FEI has two high cost extensions completed in 2009 that have no customer connections one year after construction has been completed. (Exhibit B-9, Attachment 2, BCUC IR 1.100.1) The Panel is concerned that the FEU may be constructing high cost main extensions without adequate assurance that customers will connect to the extensions. The FEU are reminded that the primary purpose of the extension and connection policies is to promote fair and equitable treatment of customers and, more specifically, to ensure that existing customers are not adversely affected by the addition of a new customer or customers (2007 System Extension Decision, 19).

6.7.2 Long-Term Sustainment Plan

In 2010, the FEU began developing the LTSP in response to the need for a longer term and systematic sustainment capital planning and asset management strategy. (Exhibit B-1, p. 340) At this time, the LTSP is not complete and the FEU will need additional time to fully implement its asset management practice enhancements. (Exhibit B-1, p. 341) Sustainment capital spending budgets were developed using existing sustaining capital with some enhanced asset management practices. (Exhibit B-1, p. 342)

The FEU submit that they need to replace approximately two thirds of their existing assets over the next 40 years. The Companies indicate that nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40 to 55 years. The FEU submit that these assets will be facing an increasing rate of deterioration as they approach the end of their service lives, leading to the need for their replacement starting within the next 10 years. The Utilities note that long range planning is necessary given the long lead times for typical large infrastructure projects. (Exhibit B-1, pp. 336-338) The LTSP represents an enhancement to existing processes used to develop sustainment capital budgets. (Exhibit B-1, p. 340)

The FEU are concerned that a large portion of a particular asset group would typically be retired from service near the average service life of the asset group as a whole, causing a spike in costs for asset replacement. They submit that 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 damage, can all impact specific assets and need to be considered. The FEU submit that these factors may result in early asset retirement in some cases, but an effective asset management program may identify opportunities to optimize the service life of assets in the particular group. (Exhibit B-1, p. 337)

The LTSP involves both operational and capital costs. Total operating costs related to the LTSP amount to $2.8 million in 2012 and $4.5 million in 2013, an increase over the projected 2011 LTSP operating costs of $1.3 million. (Exhibit B-9, BCUC IR 1.57.1) The increase in LTSP operating costs is driven by cost increases in the operations departments of Distribution and Transmission as well as Engineering. In 2012, the FEU expect to add approximately 7 employees, and an additional 4.5 employees in 2013. (Exhibit B-9, BCUC IR 1.57.1) LTSP O&M costs include planning and development costs amounting to $701 thousand in 2012 and $950 thousand in 2013 as well as capital project support costs totalling $2.12 million in 2012 and $3.557 million in 2013. Cost increases primarily relate to capital project support which includes costs historically capitalized under prior accounting policies. (Exhibit B-9, BCUC IR 1.57.1)

The FEU also seek approval of sustainment capital spending of $85.0 million in 2012 and $89.6 million in 2013. This represents incremental spending increases of approximately $25.6 million and $30.2 million in 2012 and 2013, respectively, over 2011 approved amounts. (Exhibit B-1-3, p. 19) Of that increase, $22.5 million and $31.3 million relate to the LTSP. (Exhibit B-9, BCUC IR 1.57.1)

Increased sustainment capital expenditures are primarily due to higher levels of Transmission System Reinforcements/Integrity and Reliability and Distribution Main and Service Renewals and Alterations spending. (Exhibit B-1-3, Table 6.2-5, p. 343) The FEU state that sustainment capital includes gas system improvements to ensure that there is adequate capacity on the transmission and distribution systems in order to meet forecast load and to ensure the safety, reliability and integrity of the system. (Exhibit B-1-3, p. 335)

The CEC views the Long-Term Sustainment Plan as an improvement over the 5-year capital planning approach and considers the sustainment capital requests to be appropriate. (CEC Final Submission, pp. 40-41) No other Interveners made submissions specifically on the LTSP.

The Commission Panel is supportive of the LTSP and agrees that such advanced planning is appropriate and necessary to ensure safe, reliable and economically stable delivery of natural gas for future ratepayers. Further, the Panel finds the evidence presented in support of the LTSP budgeting process, including the discussion of costs and drivers within responses to IRs to be reasonable and well developed. Accordingly, the Panel accepts the FEU proposed spending for the LTSP over the test period.

The Commission Panel agrees with the planning and methodology of the LTSP as explained in this Proceeding and further agrees that the FEU need to focus efforts to manage their aging assets in an optimal way. However, we would stress the importance of maximizing the value obtained from existing plant in service by avoiding unnecessary costs of early asset retirements and related asset losses. **Therefore, the Commission Panel directs the FEU to provide a status update on the LTSP, systems developed and the nature of assets replaced in their next revenue requirements application.**

6.7.3 Growth Capital Expenditures

(i) Growth Capital Expenditures Overview – Mainland

Growth Capital expenditures include the installation of new mains, services, meters and regulators as well as Biomethane and NGV projects. Customer additions are the primary drivers for new mains, services and meters. (Exhibit B-1, p. 359) Table 6.2-12 in the Application provides a summary of the approved, actual, projected, and forecast Growth Capital expenditures for the FEU. (Exhibit B-1-3, p. 360) In the Evidentiary Update, the NGV capital expenditures and plant additions of $4.0 million in 2012 and $3.8 million in 2013 were eliminated. (Exhibit B-21, p. 3)

The forecast level of Mains activity is based on the three year historical ratio of metres of new Mains per new Service. (Exhibit B-1-3, p. 361) For both the Mainland and Vancouver Island, the 2010 ratio of metres of new Mains per new Service is significantly lower than the three-year (2008-2010) historical ratio used to forecast the quantity of 2012 and 2013 main installations. The FEU state that the three-year historical ratio is reasonable, because it smoothes out annual fluctuations in the ratio and is consistent with past practice. (Exhibit B-9, BCUC IR 1.94.2, 1.94.4)

The forecast number of Service additions is based on a three year (2008-2010) historical ratio of Services per Gross (new) customer addition. (Exhibit B-1-3, p. 361) The forecast number of new meter installations is derived directly from the forecast of customer additions using a one to one ratio. (Exhibit B-1-3, p. 345)

Mains

The Mainland new Mains expenditures forecasts for 2012 and 2013 are $6.1 and $6.5 million, respectively (Exhibit B-1, p. 362). The forecast mains activity and unit costs are summarized in Table 6.2-14 of the Application. The forecast 2012 and 2013 mains activity level is based on a historical ratio of 13.7 metres of new Mains per new Service addition. (Exhibit B-1-3, p. 361) The

2010 metres of Mains per new Service addition, which is 9 metres of Mains per new Service addition, is significantly lower than the proposed 13.7 metres of new Mains per new Service addition. (Exhibit B-9, BCUC IR 1.94.2)

The 2012 and 2013 forecast main unit costs are the 2010 unit costs inflated by two percent annually (Exhibit B-1, p. 362). The FEU state that 2010 unit costs ($56/metre) dropped significantly from 2009 ($72/metre) as a result of the elimination of the highest cost secondary contractor in the Lower Mainland. (Exhibit B-1, p. 362)

Services

The Mainland new service expenditures for 2012 and 2013 are forecast at $12.0 and $12.9 million, respectively. (Exhibit B-1-3, p. 364) The forecast service activities and unit costs are summarized in Table 6.2-15 of the Application. The three-year historical average ratio of Service Additions to Gross Customer Additions is 0.72. (Exhibit B-1, p. 363) The forecast 2012 and 2013 unit costs are $1,569/service and $1,616/service, respectively. The 2010 cost of $1,479/service was lower than the average 2008-2009 cost of $1,709/service due to changes in the workforce, optimal crew sizing, increased activity levels, improvements in the estimation process and the elimination of a higher priced secondary contractor. (Exhibit B-1-3, pp. 363-364)

Meters

The Mainland new meters expenditures forecast for 2012 and 2013 is $2.0 million and $2.1 million respectively. (Exhibit B-1-3, p. 364) The forecast meter activities and unit costs are summarized in Table 6.2-7 of the Application. The forecast for new meters is equal to the forecast of customer additions. (Exhibit B-1-3, p. 345)

The 2012 and 2013 unit costs for new meters are $295/meter and $304/meter, respectively.
The unit cost for meter installs is derived from a blend of all customer types. The 2012 and 2013 unit costs/meter are based on the actual 2010 costs, plus 2011 forecast inflation on labour and

materials of 3 percent per annum, and $6 per meter of additional funding for customer meter set upgrades and alterations. (Exhibit B-1-3, p. 346)

(ii) <u>Growth Capital Expenditures Overview – Vancouver Island</u>

The forecast 2012 and 2013 Vancouver Island Growth Capital Expenditures are summarized in Table 6.2-16 of the Application. (Exhibit B-1, p. 365) The FEU request approval of Vancouver Island's 2012 and 2013 Growth Capital Expenditures pursuant to section 2.10(a)(i) of the Vancouver Island Natural Gas Pipeline Special Direction. (Exhibit B-1, pp. 818, 820)

<u>Mains</u>

Vancouver Island new mains expenditures forecasts for 2012 and 2013 are $2.8 million and $2.9 million respectively. (Exhibit B-1-3, p. 367) The forecast mains activity and unit costs are summarized in Table 6.2-17 of the Application. (Exhibit B-1-3, p. 365) The forecast 2012 and 2013 Mains activity level is based on a historical ratio of 12 metres of new Mains per new Service addition. (Exhibit B-1, p. 366) The 2010 metres of Mains per new Service addition is 7.3 metres of Main per new Service addition, which is significantly lower than the proposed 12.0 metres of new Mains per new Service addition. (Exhibit B-9, BCUC IR 94.4)

The 2012 and 2013 forecast unit costs are based on actual 2010 costs and 2011 cost projections, plus inflationary increases for contractor workforces of two percent in 2012 and 2013. (Exhibit B-1, p. 366)

<u>Services</u>

Vancouver Island service expenditures for 2012 and 2013 are forecast at $4.9 million and $5.3 million, respectively. (Exhibit B-1, p. 368) The forecast service activities and unit costs are summarized in Table 6.2-18 of the Application. The three-year historical average ratio of Service Additions to Gross Customer Additions is 0.81. The forecast 2012 and 2013 unit costs are

$2,252/service and $2,320/service, respectively. (Exhibit B-1-3, p. 367) Forecast unit costs are based on 2011 projections and reflect inflationary increases for both Vancouver Island and contractor workforces and equipment. The projected inflationary increases are three percent per year for both 2012 and 2013. (Exhibit B-1, p. 368)

Meters

The Vancouver Island new meters expenditures forecast for 2012 and 2013 is $0.5 million. (Exhibit B-1, p. 368) The forecast meter activities and unit costs are summarized in Table 6.2-9 of the Application. The meter forecast for new customers is equal to the forecast of customer additions. The 2012 and 2013 unit costs for new meters are $480/meter and $513/meter, respectively. (Exhibit B-1-3, p. 353) The unit cost for meter installs is derived from a blend of all customer types. The 2012 and 2013 unit costs for meters are based on 2011 projections adjusted for inflation on labour and materials of three percent. (Exhibit B-1, p. 354)

(iii) Growth Capital Expenditures Overview - Whistler

The forecast FEW new mains, service and meter expenditures are summarized in Table 6.2-19 of the Application. The FEU state that it is difficult to forecast Whistler mains activity levels, unit costs and capital expenditures due to the small volumes and wide year to year fluctuations. Whistler has assumed 1,800 metres of main will be installed in 2012 and 2013. The 2012 and 2013 forecast unit costs are based on actual 2010 costs inflated by two percent per annum to reflect expected contractor pricing changes. (Exhibit B-1, p. 369)

The forecast 2012 and 2013 service activity levels are based on the 2010 Whistler ratio of service additions to gross customer additions of 0.90. The cost of a contractor-installed service in Whistler is approximately $2,600/service. Forecast 2012 and 2013 unit costs are based on projected 2011 costs inflated by 3 percent per year. (Exhibit B-1, p. 369) The 2012 and 2013 forecast meter expenditures are based on the 2010 expenditures. (Exhibit B-1, p. 369)

(iv) Growth Capital Expenditures Overview - Fort Nelson

The forecast Fort Nelson new mains, service and meter expenditures are summarized in Table 6.2-20 of the Application. Similar to Whistler, the FEU take the position that it is difficult to forecast Fort Nelson's mains activity levels, unit costs and capital expenditures due to the low activity level and wide year to year fluctuations. The forecast 2012 and 2013 Fort Nelson main expenditures are based on the projected 2011 expenditures adjusted for inflation. (Exhibit B-1, p. 370)

The forecast 2012 and 2013 service activity levels are based on the projected 2011 Fort Nelson ratio of service additions to gross customer additions of 1.0. The 2010 cost of a local crew installing a service was $1,257/service. Forecast 2012 and 2013 unit costs are based on projected 2011 costs inflated by three percent per year. (Exhibit B-1, p. 370)

The 2012 and 2013 forecast meter expenditures are based on 2011 projections. Actual 2010 meter expenditures include one upgrade/alteration on a larger set which is not expected in 2011. (Exhibit B-1, p. 370)

(v) Growth Capital Expenditures – Biomethane

Biomethane – Mainland

The FEU forecast Biomethane expenditures of $3.1 million and $3.6 million in 2012 and 2013 (Exhibit B-1-3, p. 364). The details of these expenditures are provided in Table J-1 of the Application: Biomethane Capital Costs Summary. (Exhibit B-1, Appendix J, p. 6) FEI is currently evaluating two project partnerships with possible 2012 injection dates, one with the City of Kelowna and the other with Annacis Island. The volume from the Kelowna landfill project is expected to start at 50,000 GJ/year. The volume from the Annacis Island organic waste digester is expected to start at 100,000 GJ/year. (Exhibit B-1, Appendix J, p. 6)

On December 14, 2010, the Commission issued the Biomethane Decision. The Biomethane Decision included approval for FEI to move forward with a Biomethane Service Offering/Program for a two-year test period from the date of the Decision and established criteria for future projects. (Biomethane Decision, pp. 41-42)

(vi) <u>Growth Capital Expenditures – NGV</u>

<u>NGV – Mainland</u>

The FEU forecast zero capital investments in NGV fuelling assets in 2012 and 2013 as a result of Commission Order G-145-11 dated August 15, 2011 with Reasons. (Exhibit B-21, pp. 2-3) FEU had initially forecast NGV expenditures of $4.0 million in 2012 and $3.8 million in 2013, based on the NGV Application before the Commission (Exhibit B-1-3, p. 365 and Appendix I).

The CEC submits that the growth capital requests generally are appropriate (CEC Final Submission, p. 41). BCOAPO submits that under a multi-year term of approval there is an incentive to shift forecast capital spending from earlier years to later years. (BCOAPO Final Submission, p. 28)

Commission Determination

The Commission Panel approves the forecast 2012 and 2013 FEU growth capital expenditures for mains, services and meters. If the 2012 and 2013 actual ratio of metres of new Main per new Service is significantly lower than the three year (2008-2010) historical ratio used to forecast the quantity of 2012 and 2013 main installations, the FEU are to provide other methods for forecasting main installations in their next revenue requirements application.

The Commission Panel approves the forecast 2012 and 2013 Biomethane expenditures of $3.1 million and $3.6 million, subject to the criteria and limitations set out in the Biomethane Decision and Commission Order G-9-12 in the AES Inquiry.

The Commission Panel accepts the forecast of zero capital investments in NGV fuelling assets in 2012 and 2013.

6.7.4 Facilities and Equipment Capital Expenditures

The FEU seek approval for facilities and equipment capital expenditures amounting to $11.7 million and $3.5 million, respectively, in 2012 and $7 million and $4.2 million, respectively, in 2013. The Companies submit that a number of significant projects drive these amounts. Included is a $2 million muster station in North Vancouver which is needed due to the expiry of an existing lease. Also forecast are expenditures for a private radio network on Vancouver Island costing $1.8 million in 2012 and $2.2 million in 2013. This network purchase represents an expansion of the FEU's current private radio communications network to include Vancouver Island, which the FEU maintain is needed to ensure effective communications in an emergency. There are also $1.4 million in expenditures related to modifications to the Penticton Meter Shop and an addition to the Langley Compression Station. The FEU also request $1.5 million for office furniture to accommodate the additional staff and contractors forecast for 2012 and 2013 and to increase the density of existing employee work stations. (Exhibit B-1, p. 372, Exhibit B-1-3, p. 373)

Interveners made no submissions with respect to requested facilities and equipment capital expenditure forecasts.

The Commission Panel accepts that these facility and equipment capital expenditures are necessary to support various components of the FEU's operations and therefore approves the FEU's requests for Facilities and Equipment Capital Expenditures.

6.7.5 IT Capital

In the Application, the FEU seek approval for IT capital expenditures in 2012 and 2013 amounting to $20 million in each year. In 2011, the FEU projects IT capital expenditures equal to the approved forecast of $17.5 million. In 2010, actual IT capital expenditures totalled approximately $13.9 million, much less than the approved $17.5 million in approved forecast capital expenditures. (Exhibit B-1-4, pp. 332-333)

The FEU have identified three primary cost drivers of IT Capital projects. These include introducing/enhancing new capabilities, technology sustainment and security/risk mitigation. The Companies state that the increase of $2.5 million in requested IT capital expenditures will facilitate their ability to execute projects which have been delayed due to the focus of resources on the CCE CPCN project in 2010 and 2011. (Exhibit B-1, pp. 376-378)

CEC generally supports the FEU's IT capital expenditures budget for the test period. (CEC Final Submission, p. 41) Other interveners made no submissions with respect to the FEU's requested IT Capital expenditures.

Commission Determination

As noted in Section 6.4.8 of this Decision, the Commission Panel is concerned with the over-forecasting of costs for the FEU's IT Department in 2010. This concern relates not only to O&M costs but also to the forecasting of IT capital costs as well. While the CCE CPCN project may have created a backlog of IT projects, the Commission Panel is concerned that in 2010 alone, ratepayers paid a substantial amount in rates for projects which were not completed. While it is understood that there will be a reduction in taxes on the unspent amount, it did not offset the over collection of projected costs in rates.

As indicated in Section 6.6.1 of this Decision, the Commission directs FEU to create a deferral account to capture, net of tax, variances between forecast and actual amortization of capital assets realized by the Utilities. The Commission Panel believes that this treatment will reduce the risk that ratepayers will pay for incomplete IT capital projects in the future. **Given the introduction of**

the depreciation deferral account, the Commission Panel approves the FEU's IT capital budget for 2012 and 2013.

In addition, the Commission Panel reminds the Utilities that, when planning for IT capital expenditures, the FEU should take into consideration their relatively flat customer base. In the view of the Panel, an increase in IT capital expenditures in the future should be remedial in nature, and demonstrate a clear ability to correct inadequate operational matters or reduce other operating costs from the status quo. **Therefore, the Commission Panel directs the FEU in future RRAs to clearly identify either a shortcoming in current customer service levels or provide a fulsome budgeted O&M cost reduction, including the year of realization of expected savings, resulting from each significant IT Capital project in order to justify spending requests.**

6.7.6 LNG Tanker

The FEU purchased a second LNG tanker in December, 2010. Its first LNG tanker is fully depreciated, having been purchased in 1996 as a partially depreciated asset. The first tanker does, however, remain used and useful and provides transport service to LNG customers. The second tanker is to be used primarily as a backup resource to the first tanker, for system reliability and integrity during planned and unplanned outages. It is also proposed to be used, when available, to provide transport service to LNG customers. The Companies propose to use the incremental revenue from the provision of transport service to LNG customers to offset the cost of service of the new tanker. The FEU advise that it was necessary for them to purchase the second tanker in order to comply with Transport Canada requirements for FEI's Emergency Response Plan as Transport Canada will not allow the use of a damaged tanker for the transport of LNG. (Therefore, an alternate tanker must be available in the event of damage to one of the tankers). Accordingly, the Companies submit that the second tanker is properly included in rate base as its primary purpose is to provide backup supply to the system during emergency outages as well as for scheduled work.

The FEU have accounted for the second tanker by capitalizing it to Property, Plant and Equipment, with depreciation commencing immediately. This treatment is based on the premise that the tanker is standby equipment and therefore providing a service from the moment it is available. (Exhibit B-22, BCUC Supplemental IR 1.1-1.12)

Commission Determination

The Commission Panel approves the inclusion of the second tanker in rate base. The Panel finds that the FEU have established the need of having one standby tanker. The Commission Panel accepts that the proposed depreciation method is an acceptable accounting practice, however, the Panel is not convinced that the depreciation methodology proposed is the best technique in the particular circumstances of this case. In the Panel's view, history has shown that the depreciation charged for the first tanker was not consistent with its useful life, as it is fully depreciated and is still used and useful. In the Panel's view, the amount of use of the tankers for backup supply and for transportation service to LNG customers going forward may be more relevant. It seems to be clear that the second tanker will not simply be used for standby, although that is its primary purpose and the reason for its inclusion in rate base. **The Commission Panel accepts the proposed depreciation methodology for the new tanker for the purposes of setting rates in the test period, however, the Commission Panel directs the FEU to provide an estimate of the useful life of the new tanker which is related to hours of use in addition to the estimate already provided, taking into account the forecast use for transportation services to LNG customers.** As noted in the earlier CNG/LNG Decision, the Commission Panel is concerned that natural gas distribution ratepayers bear none of the costs of the NGV business.

6.7.7 <u>Mobile Refuelling Station</u>

The FEU also purchased a mobile LNG refuelling unit (IMC 6000) in December of 2010 for $428,000. They seek to place this asset in service and include it in their rate base as LNG Dispensing Equipment. (Exhibit B-17, BCUC IR 2.135.1)

Commission Panel Determination

The Commission Panel denies this request. Inclusion of a mobile LNG refuelling unit in rate base at this time would require non bypass natural gas ratepayers to shoulder the burden/risk of the cost of this asset. This is not consistent with the CNG/LNG Decision.

In the CNG/LNG Decision the Commission Panel in that proceeding went to some lengths to express its concern that all costs associated with CNG/LNG projects be borne by those customers and not general ratepayers. The Panel stated:

> "the Panel finds that FEI has failed to provide a convincing argument that it is just and reasonable that existing ratepayers should subsidize the costs of the refuelling facilities. We believe that there should be as little potential for cross-subsidization as it is possible to achieve. The Panel is concerned about the effect of unbudgeted costs, cost overruns and other factors that could require ratepayer subsidization. The Panel therefore requires that, to the extent possible, none of the actual costs of the CNG/LNG service offerings be recovered from existing ratepayers." (CNG/LGN Decision, p. 24)

That message is reflected in various directives throughout the CNG/LNG Decision. The cost of the mobile LNG refuelling station is, in this Panel's view, outside the costs advanced by FEI in the CNG/LNG Application as likely or necessary (and therefore included in the cost of service). The cost for the mobile refuelling unit is, therefore, beyond the specific costs contemplated by the Panel in the CNG/LNG Decision as well as Section 12B of the General Terms and Conditions which have been approved.

Accordingly, the Commission Panel finds that this asset is not an asset which should in any way be for the account of the natural gas distribution ratepayer and, to the extent that the FEU have included this asset in rate base, directs the FEU to remove the associated costs. The cost of this asset is therefore for the account of the shareholder, and the shareholder may attempt to recover its cost from LNG customers, perhaps through a rental or other charge.

6.8 Use of Deferral Accounts

For the FEU rate base deferral accounts, the mid-year balance is included in the rate base calculation for the Utilities. The forecast of mid-year balances of deferral accounts by category is set out in the table below. Deferral accounts will be addressed within each applicable category.

Table 6.4
Forecast Mid-Year Balances of Deferral Accounts by Category

2012 Forecast, Mid Year Balance ($thousands)					
	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
(A) Margin Related	$(10,027)	$(4,062)	$703	$(41)	$ (13,427)
(B) Energy Policy	27,599	3,163	75	-	30,837
(C) Non-Controllable	(594)	40	(189)	(4)	(746)
(D) Application Costs	1,992	172	147	3	2.313
(E) Other	11,902	66	26,773	52	38,794
(F) Residual	711	-	-	-	711
Mid Year Balance, Deferral Accounts	**$31,583**	**$(621)**	**$27,509**	**$10**	**$58,481**

2013 Forecast, Mid Year Balance ($thousands)					
	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
(A) Margin Related	$1,544	$-	$480	$(8)	$2,017
(B) Energy Policy	37,805	4,316	218	-	42,339
(C) Non-Controllable	2,259	35	(115)	(2)	2,177
(D) Application Costs	1,368	72	9	1	1,450
(E) Other	6,247	932	25,958	91	33,228
(F) Residual	684	-	-	-	684
Mid Year Balance, Deferral Accounts	**$49,909**	**$5,355**	**$26,550**	**$82**	**$81,896**

(Exhibit B-1-3, Table 6.3-2, p. 386)

In addition to deferral accounts within these six categories, the FEU seek approval to establish the Fort Nelson 2012 Revenue Surplus Account to record the 2012 Fort Nelson revenue surplus for return to customers in 2013. (FEU Final Submission, pp. 9-10) The Utilities also request approval to discontinue three deferral accounts, including the Residential Commodity Unbundling Account, the Commercial Commodity Unbundling Account, and the IFRS transitional Account. These deferral accounts are no longer in use. (Exhibit B-1, Appendix G)

Commission Determination

The Commission Panel agrees that the Fort Nelson Revenue Surplus Account provides rate consistency for 2012. **The Commission Panel approves the creation of the Fort Nelson Revenue Surplus Account as requested by the Utilities.**

The Commission Panel finds that unused deferral accounts should be discontinued. **The Commission Panel approves the discontinuance of the Residential Commodity Unbundling Account, the Commercial Commodity Unbundling Account, and the IFRS transitional Account.**

(A) Margin Related Deferral Accounts

The margin related deferral accounts that are in place have been approved in previous Commission proceedings. In the current Proceeding the only account in this category that was subject to questioning was the GCVA for FEVI. Questions on this account focused on the proposal by FEVI to cease reporting on account balances on a quarterly basis. This request will not impact the treatment of the deferral account and will be addressed in Section 7.5. (FEU Final Submission, p. 152)

The FEU request modifications to existing margin related deferral accounts in order to standardize treatment of these accounts within the FEU. (Exhibit B-1-3, p. 387; Exhibit B-1, pp. 388-391; FEU Final Submission, p. 152) The mid-year balances in each of the margin related deferral accounts for 2012 and 2013 are as set out in the Tables below.

Table 6.5
Margin Deferral Accounts

2012 Forecast, Mid Year Balance ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account	$(11,604)	$-	$(88)	$-	$(11,692)
(CCRA)	15,506	-	99	-	15,604
Midstream Cost Reconciliation Account	(6,937)	-	703	(16)	(6,250)
(MCRA)	(2,164)	-	(11)	3	(2,172)
Revenue Stabilization Adjustment Mechanism	94	-	-	-	94
(RSAM)	-	(4,062)	-	-	(4,062)
Interest on CCRA/MCRA/RSAM/Gas in Storage	-	-	-	(28)	(28)
Revelstoke Propane Cost Deferral Account	(4,922)	-	-	-	(4,922)
Gas Cost Variance Account					
Fort Nelson Gas Cost Reconciliation Account					
SCP Mitigation Revenues Variance Account					
Total Mid Year Margin Related Balance	**$(10,027)**	**$ (4,062)**	**$703**	**$(41)**	**$(13,427)**

2013 Forecast, Mid Year Balance ($ thousands)					
Margin Related Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Commodity Cost Reconciliation Account	$-	$-	**$ -**	$-	$-
(CCRA)	9,303	-	59	-	9,363
Midstream Cost Reconciliation Account	(4,162)	-	422	(9)	(3,750)
(MCRA)	(1,007)	-	(1)	2	(1,006)
Revenue Stabilization Adjustment Mechanism	-	-	-	-	-
(RSAM)	-	-	-	-	-
Interest on CCRA/MCRA/RSAM/Gas in Storage	-	-	-	-	-
Revelstoke Propane Cost Deferral Account	(2,590)	-	-	-	(2,590)
Gas Cost Variance Account					
Fort Nelson Gas Cost Reconciliation Account					
SCP Mitigation Revenues Variance Account					
Total Mid Year Margin Related Balance	**$1,544**	**$-**	**$480**	**$ (8)**	**$2,017**

(Exhibit B-1-3, Table 6. 3-3 p. 387)

The Commission Panel finds that the modifications to margin related deferral accounts are appropriate and in the interest of ratepayers and approves them as filed. The Commission Panel approves the continuation of existing margin related deferral accounts as applied for as they continue to reduce rate volatility.

(B) Energy Policy Deferral Accounts

The FEU have applied for six deferral accounts that are associated with the FEU activities designed to help meet British Columbia's energy objectives through the reduction of greenhouse gas emissions. The FEU are also applying to establish Energy Efficiency & Conservation deferral account mechanisms to support the program's operations. (Exhibit B-1-3, 392) The FEU's estimate of the mid-year balances of these energy policy deferral accounts is set out in the Tables below.

Table 6.6
Energy Policy Deferral Accounts

2012 Forecast Mid-Year Balance ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC) NGV Conversion Grants Emissions Regulations 2010-2011 Biomethane Program Costs 2011 CNG and LNG Service Costs and Recoveries NGV Incentives	$22,720 101 - 748 (24) 4,054	$3,147 17 - - - -	$75 - - - - -	$- - - - - -	$25,941 118 - 748 (24) 4,054
Total Mid-Year Balance	**$27,599**	**$3,163**	**$75**	**$-**	**$30,837**

2013 Forecast Mid-Year Balance ($ thousands)					
Energy Policy Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
Energy Efficiency & Conservation (EEC) NGV Conversion Grants Emissions Regulations 2010-2011 Biomethane Program Costs 2011 CNG and LNG Service Costs and Recoveries NGV Incentives	$33,219 119 - 449 (36) 4,054	$4,290 26 - - - -	$218 - - - - -	$- - - - - -	$37,727 145 - 449 (36) 4,054
Total Mid-Year Balance	**$37,805**	**$4,316**	**$218**	**$-**	**$ 42,339**

(Exhibit B-1-3, Table 6.3-4, p. 392)

Energy Efficiency and Conservation Deferral Account

Section 8.0 deals with Energy Efficiency and Conservation Issues and the Energy Efficiency and Conservation Deferral Account will be dealt with at that time. **The FEU are directed to recalculate the mid-year balances in the Energy Efficiency and Conservation deferral account based on the Commission determinations with respect to this account in Section 8.0.**

NGV Conversion Grants

FEI and FEVI maintain a NGV Conversion Grant Program, as approved by Commission Order G-98-99[12] for FEI and Commission Order G-140-09[13] 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. (Exhibit B-1, pp. 395-396) **The Commission Panel finds the NGV Conversion Grant Program deferral account as applied for is appropriate and is approved.**

Emissions Regulations Deferral Account

FEU assert that a 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 the 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

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[12] In the Matter of An Application by BC Gas Utility Ltd. for Approval of Amendments to Natural Gas Vehicle Program; Order G-98-99 dated September 16, 1999

[13] In the Matter of 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; Order G-140-09 dated November 26, 2009 (TGVI 2010-2011 RRA Decision)

mechanisms aimed to reduce greenhouse gas emissions in British Columbia. These two regulations impact the FEU in two ways: 1) The FEU are required to reduce their own operating emissions, and 2) the FEU can sell their credits from renewable energy to other firms or use them to offset excessive emissions in other parts of the FEU's operations. (Exhibit B-1, pp. 396-397)

The *Emissions Trading Regulation* has yet to be legislated. Recent developments in California and British Columbia make it uncertain whether requirements will be imposed on the Companies.

The Province of BC has legislated the *RLCFRR* which addresses the transportation sector's contribution to GHG emissions in BC. This regulation allows for emissions credits and obligations based on a required carbon intensity baseline. Those suppliers who are not in compliance with the mandated reductions in carbon will be required to purchase credits from others or pay a penalty of $200/tonne for deficiencies. Starting in 2011, Part 3 fuel suppliers must 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. As noted by the FEU, Part 2 or Part 3 fuel suppliers manufacturing fuel in the province for the first time, or using it for the first time, are responsible for compliance unless there is a written agreement stating otherwise. (Exhibit B-1, p. 397) Since the FEU sell natural gas for transportation under various rate classes, they have the opportunity to claim first sale as a 'Part 3' fuel supplier in the Province. If the Companies add CNG and LNG sales, their credits will to increase as credits are measured against the conventional fuel intensity baseline, which creates a potential additional revenue stream. (Exhibit B-1, pp. 396-397)

Given the uncertainties, the FEU find it difficult to forecast associated costs and revenues with cap and trade and *RLCFRR* regulations and request a deferral account to capture both compliance costs and revenues collected associated with these regulations. For 2012 and 2013 the FEU are not forecasting any additions to this account and any amortization of balances in the account would occur outside the test period. (Exhibit B-1, pp. 396-397) The costs related to existing and known regulations, including the *GHG Reporting Regulation*, are embedded in the O&M expenditures forecast in this RRA and these costs will not be charged to the deferral account.

The FEU state that they will track and record all costs and revenues related to emissions regulations and will follow the Companies' existing accounting policies for tracking and recording costs and revenues in the appropriate cost centre or deferral account when incurred. The Environment, Health & Safety (EH&S) group will be responsible for and looking after the Compliance with the Emissions Regulations deferral account. Once new regulations come into effect, the FEU will create the necessary internal orders and accounts to capture the costs.

Commission Determination

The Commission Panel finds that establishment of an Emission Regulations Deferral Account is appropriate given the uncertainties surrounding the costs and revenues that could accrue to the FEU. In the event the FEU determine that costs and/or revenues have occurred that should accrue to the deferral account, they are to provide to the Commission with a detailed description of the accounting methodologies that they are using to track and record such costs and/or revenues.

Biomethane Variance Account

The Commission approved the Biomethane Variance Account as a rate base account to be used to capture any differences between forecast Biomethane service costs and revenues, the balance to be recovered through the Biomethane Energy Recovery Charge. (Biomethane Decision, pp. 49, 58)

In this Application, the FEU are seeking to change the Biomethane Variance Account from a rate base variance account to a non rate base variance account. FEU submit that this change will ensure that any balance in this account is recovered from Biomethane customers only in a transparent fashion and that the balance does not contain any rate base return. (FEU Final Submission, pp. 154-155)

Commission Determination

The Commission Panel accepts the FEU proposal and approves the change for the Biomethane Variance Account from rate base to non rate base. The FEU have not requested a change to the treatment of the other two deferral accounts which were created as part of the Biomethane program.

CNG and LNG Service Recoveries Deferral Account

In addition to the non-rate base 2011 CNG and LNG Service Costs and Recoveries Deferral Account which was established to cover the Waste Management application costs, the Commission approved a rate base CNG and LNG Service Recoveries Deferral Account in the CNG/LNG Decision. This deferral account was approved on the basis that it would capture incremental CNG and LNG Service recoveries received from actual volumes of product purchased in excess of minimum contract take or pay commitments. It was ordered to be refunded to all non-bypass customers by amortizing the balance through delivery rates over a one year period, commencing the following year, to be effective as of January 1, 2012.

In this Application, FEI seeks approval to expand this account to include variations from the revenue forecast pertaining to Rate Schedule 16 as well as all variances to LNG Service and LNG Tanker revenues. FEI believes that a deferral account is appropriate because Rate Schedule 16 is a relatively new rate schedule and, at the time of the filing of the Application, there were no customers using this service. Vedder Transportation is expected to be the first customer to use this Rate Schedule beginning in the second half of 2011. While FEI believes its CNG and LNG service 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. (Exhibit B-9, BCUC IR 1.112.1, 1.112.2)

FEI proposes that additions to this account over the forecast period will be recovered from or refunded to all non-bypass customers beginning in 2014. (Exhibit B-1, p.399)

Commission Determination

The Commission Panel does not believe that the expansion of the CNG and LNG Service Recoveries Deferral Account to include variations in the revenue requirement from Rate Schedule 16, LNG Service and LNG Tanker service is appropriate. As noted earlier, the Commission Panel in the CNG/LNG Decision went to some lengths to express its concern that existing ratepayers be insulated from any risk arising from the new CNG/LNG activities and that all possible associated costs be borne by the CNG/LNG customers who stood to benefit from the service offerings. The Panel sees no need to depart from that determination in this Proceeding. In the view of the Panel, there is no need to protect CNG/LNG customers and the shareholder at the potential expense of existing ratepayers.

Accordingly, the Commission Panel denies the request to expand the use of the CNG and LNG Service Recoveries Deferral Account for the 2012 and 2013 forecast period.

NGV Incentives Deferral Account

In the EEC NGV Incentives Review Decision,[14] the Commission determined that EEC monies provided by the Companies to fund incentives for NGVs were expended without prior approval and that it was not appropriate for the Companies to have changed the scope of a program to include such expenditures. The Commission did not, however, make a determination on the issue of whether those incentive payments should be eligible for cost recovery from ratepayers, in whole or in part, but indicated that it was prepared to receive submissions on the issue of prudency in respect of some or all of the expenditures in issue.

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[14] In the Matter of Terasen Energy (Vancouver Island) Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review; Decision and Order G-145-11 dated August 15, 2011 (EEC NGV Incentives Review Decision)

In this Application, FEI has included $5.6 million in a new "NGV Incentives deferral account, with the recovery period to be determined pending any further review and decision on the prudency of these amounts." (Exhibit B-1-3 p. 399)

Commission Determination

The Commission Panel approves the creation of the NGV Incentives deferral account attracting no return. As a result of the circumstances outlined in the EEC NGV Incentive Review Decision, the Panel concludes that the FEU should not receive a return at this time on the funds. A final determination as to whether the deferral account should attract a return is left to the prudency review.

(C) 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 the Table below.

Table 6.7
Non-Controllable Item Deferral Accounts

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)	$(1,262)
Insurance Variance	(578)	-	-	-	(578)
Pension & OPEB Variance	7,978	-	-	-	7,978
BCUC Levies Variance	118	-	-	-	118
Interest Variance	(3,928)	-	(275)	(2)	(4,204)
Tax Variance Account	(3,513)	-	(1)	-	(3,514)
Vancouver Island HST Implementation	-	(66)	-	-	(66)
Olympic Security Costs	285	67	2	-	353
IFRS Conversion Costs	384	39	5	-	428
Customer Service Variance Account	-	-	-	-	-
Total Mid-Year Balance, Non-Controllable Items Deferrals	**$(594)**	**$40**	**$(189)**	**$(4)**	**$(746)**

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)	-	(165)	(1)	(2,323)
Tax Variance Account	(3,513)	-	-	-	-
Vancouver Island HST Implementation	-	-	-	-	-
Olympic Security Costs	-	22	(2)	-	114
IFRS Conversion Costs	128	13	2	-	143
Customer Service Variance Account	-	-	-	-	-
Total Mid-Year Balance, Non-Controllable Items Deferrals	**$2,259**	**$35**	**$40**	**$(2)**	**$2,177**

(Exhibit B-1-3, Table 6.3-8, p. 400)

FEVI 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. (Exhibit B-1-3, p. 400, Exhibit B-1, pp. 401-403) Further, the FEU seeks approval to establish a Customer Service Variance Account to defer the variances in forecast and actual costs resulting from the various uncertainties arising from the implementation of a new Customer Service delivery module. The period of amortization will be applied for in a future revenue requirements application. (Exhibit B-1, p. 404)

Also, the FEU seeks approval for modifications to various amortization periods for existing non-controllable deferral accounts within FEW and Fort Nelson to standardize deferral account treatment with existing FEI policies. (Exhibit B-1-3, p. 400, Exhibit B-1, pp. 401-404)

Commission Determination

The Commission Panel notes that deferral account treatment is appropriate where certain costs are significant and beyond the control of the FEU and could result in windfall benefits or costs to ratepayers. The Panel further notes that a level of uncertainty with customer service variance accounts exists in the test period as implementation is ongoing. **Accordingly, the Commission Panel approves the creation of the Customer Service Variance Account as applied for with the**

amortization period to be determined in the next revenue requirements application of the FEU.

The Commission Panel has one area of concern with respect to existing non-controllable Item deferral accounts. Insurance costs, while having elements that are beyond the Companies' control, such as changes related to economic circumstances and natural disasters, also have elements they can control. These include factors such as changes in deductibles before insurance coverage begins or self insurance for certain assets. Given the current economic circumstances where there is considerable uncertainty on a global scale, the Commission Panel accepts the insurance variance deferral account at this time. The Companies are requested to revisit the appropriateness of the non-controllable deferral accounts at the time of their next revenue requirements application.

Given the continued uncertainties beyond the control of the Companies, the Commission Panel approves the continuation of non-controllable items deferral accounts as applied for. The Commission Panel also agrees that standardization of the FEU's deferral accounting policies simplifies and streamlines record keeping. **Accordingly, the Commission Panel approves the requested modifications to existing non-controllable deferral accounts.**

(D) BCUC Cost of Applications Deferral Account

The FEU estimate total mid-year balances for its BCUC Applications deferral account to be $2.313 thousand for 2012, and $1.450 thousand for 2013 as shown in the Table below. These costs are driven by various different processes before the BCUC that the Companies are currently involved in or in which they have been involved.

Table 6.8
Application Cost Deferral Accounts

2012 Forecast, Mid-Year Balance ($ thousands)					
Application Cost Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$582	$34	$4	$-	$621
2010-2011 Revenue Requirements	(82)	-	132	-	50
Application	654	70	7	3	734
2012-2013 Revenue Requirements	178	17	2	-	197
Application	123	-	-	-	123
CCE CPCN Application	-	35	-	-	35
NGV for Transportation Application	393	-	-	-	393
Victoria Regional Office CPCN	144	16	2	-	162
AES Inquiry Cost					
Long Term Resource Plan Application					
Total Mid Year Balance, Application Cost Deferrals	**$1,992**	**$172**	**$147**	**$3**	**$2,313**

2013 Forecast, Mid-Year Balance ($ thousands)					
Application Cost Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
2009 ROE & Cost of Capital Application	$414	$20	$3	$-	$437
2010-2011 Revenue Requirements	-	-	-	-	-
Application	218	23	2	1	245
2012-2013 Revenue Requirements	122	11	1	-	134
Application	74	-	-	-	74
CCE CPCN Application	-	-	-	-	-
NGV for Transportation Application	382	-	-	-	382
Victoria Regional Office CPCN	159	-	-	-	180
AES Inquiry Cost					
Long Term Resource Plan Application					
Total Mid Year Balance, Application Cost Deferrals	**$1,368**	**$72**	**$9**	**$1**	**$1,450**

(Exhibit B-1-3, Table 6.3-10 p. 405)

In the Application, the FEU request approval to establish three new application cost deferral accounts as follows:

1) <u>2012-2013 Revenue Requirement Application Costs:</u>

   The FEU seek approval to account for costs related to this Application within a new deferral account for amortization over a period of two years commencing in fiscal 2012.

2) <u>AES Inquiry Costs:</u>

   The FEU seek approval to account for costs related to the AES Inquiry application within a new deferral account for amortization over a period of five years commencing in 2012.

3) <u>Long Term Resource Plan Application Costs:</u>
   The FEU seek approval to account for costs related to the upcoming Long Term Resource Plan Application, that are forecast for the test period, within a new deferral account for amortization over a period of two years commencing in 2013.

(Exhibit B-1-3, pp. 405-406)

Commission Determination

The Commission Panel acknowledges that this Application, the FEU Inquiry and the upcoming Long Term Resource Plan application will have an impact on ratepayers beyond the current year and that deferral of these accounts is warranted. Further, the Commission Panel acknowledges that the numerous regulatory proceedings that the FEU are involved in create uncertainty with respect to the magnitude of the costs that will be incurred by the FEU, thus also warranting the use of deferral accounts.

The Commission Panel approves the new deferral accounts for the 2012-2013 Revenue Requirements Application, AES Inquiry and Long Term Resource Plan application as applied for. **The Commission Panel approves the continuation of other deferral accounts for BCUC application costs as applied for.**

(E) Other Deferral Accounts

The FEU have applied for the following deferral accounts listed in the Tables below. These include both previously approved deferral accounts and new accounts. Four Whistler Pipeline and

Conversions cost deferral accounts have been approved pursuant to Orders G-53-06,[15] G-35-09[16] and G-138-10.[17] Significant accounts also include US GAAP and Pension & OPEB accounts for which approvals are sought in this Application. (Exhibit-1-3, p. 407)

Table 6.9
Other Deferral Accounts

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	-	-	13,724	-	13,724
Vancouver Island	-	-	(217)	-	(217)
Pipeline Contribution Costs Variance	(104,859)	(16,682)	-	-	(121,541)
Account	2,184	336	3	-	2.522
Pension & OPEB Funding	11,064	1,016	72	96	12,249
Deferred Removal Costs	-	-	-	(44)	(44)
Gains and Losses on Asset Disposition	256	29	3	-	287
2011 Muskwa River Crossing	79,958	11,922	-	-	91,880
US GAAP Conversion Costs	(1,444)	(361)	-	-	(1,805)
US GAAP Pension & OPEB Funded Status	-	1,030	-	-	1,030
US GAAP Transitional Costs	23,876	2,679	261	-	26,816
PCEC Start Up Costs	534	60	6	-	600
2010-2011 Customer Service O&M and	334	38	4	-	375
COS					
Gas Asset Records Project					
BC OneCall Project					
Total Mid Year Balance, Other Deferrals	**$11,902**	**$66**	**$26,773**	**$52**	**$38,794**

[15] In the Matter of A Submission by Terasen Gas (Whistler) Inc. for Review of its 2005 Resource Plan Update and An Application by Terasen Gas (Whistler) Inc. for a Certificate of Public Convenience and Necessity to convert its propane grid system to natural gas and approval to enter into a Natural Gas Transportation Service Agreement with Terasen Gas (Vancouver Island) Inc. and An Application by Terasen Gas (Vancouver Island) Inc. for a Certificate of Public Convenience and Necessity for a natural gas pipeline lateral from Squamish to Whistler; Order G-53-06 dated May 19, 2006

[16] In the Matter of An Application by Terasen Gas (Whistler) Inc. For Approval to Amend its Schedule of Rates effective January 1, 2009 And for a Return on Equity and Capital Structure; Decision and Order G-35-09 dated April 17, 2009

[17] In the Matter of Terasen Gas (Whistler) Inc. 2010-2011 Revenue Requirements and Rates Application; Order G-138-10 dated September 1, 2010; Decision dated October 25, 2010

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	-	-	13,435	-	13,435
Island	-	-	-	-	-
Pipeline Contribution Costs Variance Account	(105,071)	(15,021)	-	-	(120,092)
Pension & OPEB Funding	728	112	1	-	841
Deferred Removal Costs	10,497	964	69	91	11,621
Gains and Losses on Asset Disposition	-	-	-	-	-
2011 Muskwa River Crossing	256	29	3	-	287
US GAAP Conversion Costs	75,515	11,360	-	-	86,875
US GAAP Pension & OPEB Funded Status	(496)	(283)	-	-	(779)
US GAAP Transitional Costs	-	985	-	-	986
PCEC Start Up Costs	22,366	2,510	245	-	25,121
2010-2011 Customer Service O&M and COS	1,535	173	17	-	1,725
Gas Asset Records Project	918	103	10	-	1,031
BC OneCall Project					
Total Mid Year Balance, Other Deferrals	**$6,247**	**$932**	**$25,958**	**$91**	**$33,228**

(Exhibit B-1-3, Table 6.3-11 p. 407)

The following Other deferral accounts have been previously reviewed and approved by the Commission:

- Whistler Pipeline and Conversion Costs
- Whistler Capital Contribution to Vancouver Island
- Pipeline Contribution Costs Variance Account
- US GAAP Conversion Costs
- PCEC Start Up Costs
- Pension and OPEB Funding

(Exhibit B-1, pp. 408-409, B-1-3, pp. 408, 410, 411)

These Other deferral accounts are consistent with past Commission decisions and are approved as applied for.

The following Other deferral accounts have been previously reviewed and approved by the

Commission, but in this application the FEU are requesting some change to the treatment of the account.

Account	Proposed Change
Gains and losses on asset disposition	The FEU propose 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.
Deferred Removal Costs	The FEU propose to amortize the balance in delivery rates over two years rather than one due to the magnitude of the balances. The amortization would begin January 1, 2012.
2010-2011 Customer Service O&M and COS	The FEU are seeking approval in this Application to (a) allocate the balance in this deferral account amongst the FEU on the basis of average customers, and (b) amortize the amount in delivery rates over eight years. This is the same amortization period that was authorized in the CCE Decision.

Commission Determination

The Commission Panel finds the proposed changes of the Other deferral accounts to be reasonable because the changes reflect a more accurate match of costs to their associated benefits. Therefore, the Commission Panel approves the changes as applied for.

The FEU are also applying for four new deferral accounts within this category.

Gas Records Project

FEU are requesting funding for a gas records project in order to meet new requirements for records management in order to provide greater assurances of pipeline safety and integrity through better documentation and handling of gas system asset compliance records. The Companies are asking for a deferral account that would amortize the costs of this project over five years commencing on January 1, 2012. They believe the five year amortization period is appropriate given the magnitude of the project and that five years generally coincides with the period over the estimated cost of

$7.8 million will be incurred. Only actual costs will be recorded in the Gas Records Project Deferral Account and will be allocated on the basis of the average number of customers, resulting in an allocation of 89 percent to FEI, 10 percent to FEVI and 1 percent to FEW. (Exhibit B-1, pp. 412-413, Exhibit B-1-3, pp. 411, 414)

Commission Determination

The Commission Panel finds the establishment of a deferral account for the Gas Records Project is reasonable and that a five year period is appropriate given the expected duration of the project.

US GAAP Deferral Accounts

In addition to the US GAAP Conversions Cost account approved by Order G-117-11, the FEU propose three new deferral accounts.

- US GAAP Transitional Account. This is to be a one-time deferral account to capture the unamortized pension and Other Post-Employment Benefits (OPEB) transitional obligation amortized by plan over the expected average remaining service life (EARSL) with an offsetting entry to the Pension & OPEB Funding deferral account.
- US GAAP Pension and OPEB Funded Status Account. This is a proposed new and ongoing deferral account to capture the annual pension and OPEB funded status adjustment, with an offsetting entry to the Pension and OPEB Funding deferral account.
- US GAAP Uncertain Tax Positions Deferral Account. This is a proposed non-rate base, new deferral account to capture any differences on an ongoing basis that arise from the implementation of US GAAP Accounting Standards Board Interpretation No. 48.

(Exhibit B-1-3, pp. 46, 410, Exhibit B-1, p. 45)

Commission Determination

The Commission Panel finds these proposed new deferral accounts appropriate given the approval of the FEU's move to US GAAP. **The three new US GAAP Deferral Accounts namely the US GAAP Transitional Account, US GAAP Pension and OPEB Funded Status Account and US GAAP Uncertain Tax Positions Deferral Accounts are approved as applied for.**

Muskwa River Crossing 2011

The FEU seek approval to establish a deferral account to accumulate and refund revenues collected in the Fort Nelson service area related to the delayed construction of the Muskwa River Crossing Project. (Exhibit B-1-3, p. 410)

The Commission Panel finds this proposed new deferral account appropriate given the delayed construction of the Muskwa River Crossing. **The new Muskwa River Crossing 2011 Deferral Account is approved as proposed.**

BC One Call Project

The FEU have applied to put in place a BC One Call Ticket Process Improvement Project. This project will significantly reduce the manual processes currently utilized within the system today. Various technologies will be integrated allowing certain BC One Call information packages to be assembled with little or no human intervention. The project is estimated to cost $2.3 million spent over three years. Upon completion, it is estimated to provide an O&M cost saving of approximately $540,000 annually. The FEU have requested a deferral account to manage the costs of the BC One Call project. They propose to amortize the costs over five years commencing on January 1, 2012. Only actual project costs will accrue to the deferral account. Allocation of costs will be on the basis of the average number of customers. The resulting allocation is 89 percent to FEI, 10 percent to FEVI and 1 percent to FEW. (Exhibit B-1, pp. 415-418)

Commission Determination

The Commission Panel finds the establishment of a deferral account as proposed for the BC One Call Project appropriate given potential uncertainties with costs and the timing of the project. The proposed allocation of costs is consistent with the cost allocation methodology applied to similar types of projects. The BC One Call Project Deferral Account is approved as proposed.

(F) Residual Deferral Accounts

FEU continue to use the previously approved deferral accounts listed in the Tables below. The most significant of these deferral accounts is the SCP Tax Reassessment deferral account related to an ongoing tax matter that FEU expects to resolve in the test period. This account was approved pursuant to Orders G-160-06[18] and G-153-07[19] (Exhibit B-1, p. 418). In this Application, the FEU seek approval to establish a Residual Delivery Rate Riders Deferral Account. The purpose of this account is to combine three existing residual deferral accounts, the ROE Revenue Requirement Variance Account and the Lockburn Land Cost and Delivery Rate Refund Rider deferral accounts, into a single account. The FEU propose to recover the new account over the 2012 fiscal year. (Exhibit B-1-3, p. 420)

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[18] In the Matter of Terasen Gas Inc. Application for Approval of 2007 Revenue Requirements and Delivery Rates; Decision and Order G-160-06 dated December 14, 2006

[19] In the Matter of An Application by Terasen Gas Inc. for Approval of 2008 Revenue Requirements and Delivery Rates; Order G-153-07 dated December 10, 2007

Table 6.10
Residual Deferral Accounts

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 Rider	89	-	-	-	89
				-	
Total Mid Year Balance, Residual Deferrals	**$711**	**$-**	**$(23)**	**$-**	**$688**

2013 Forecast, Mid-Year Balance ($ thousands)					
Residual Deferral Accounts	**Mainland**	**Vancouver Island**	**Whistler**	**Fort Nelson**	**Total**
SCP Tax Reassessment	$684	$-	$-	$-	$684
Other	-	-	-	-	-
Residual Delivery Rate Rider	-	-	-	-	-
Total Mid Year Balance, Residual Deferrals	**$-**	**$-**	**$-**	**$-**	**$684**

(Exhibit B-1, Table 6.3-16, p. 418)

Commission Determination

The Commission Panel finds that combining three deferral accounts into a single Residual Delivery Rate Riders Deferral Account streamlines the account management of these deferral accounts. **The Commission Panel approves the creation of the Residual Delivery Rate Riders Deferral Account as requested.**

The Commission Panel finds that the existing residual deferral accounts continue to be appropriate and in the interest of ratepayers and approves them as filed.

6.9 Performance Metrics

FEU uses a “Balanced Scorecard” to measure performance success. The Scorecard has four categories of measures with 10 measures in total. These are:

Financial

- FEU net earnings

Customer

- O&M per customer
- Base capital
- Customer satisfaction

Key Processes

- Credit and collections and control of bad debts
- Execution against Regulatory Priorities

Employee

- Recordable vehicle accidents
- Recordable injuries
- Wellness
- Public safety

The FEU assert that the balanced scorecard is an appropriate tool for assessing the performance of the Utilities against Commission-approved budgets. (FEU Final Submission, p. 25)

The CEC submits that the incentives in the balanced scorecard are misaligned from ratepayers interests and that, in the past, have generated results which are detrimental to those interests. In CEC's view, the Commission should find that the budget guidelines and processes as well as the performance measurement and tracking of the FEU are less than adequate for assuring productivity improvements. CEC submits that the Commission should set rates for the FEU based on lower O&M and Capital Rate Base values than the FEU have applied for, in part to compensate for this inadequacy. (CEC Final Submission, p. 18)

The FEU argue that their consistent success in meeting their targets speaks to the prudent management of the Utilities to the benefit of the shareholder and customers alike.

Commission Determination

As outlined in Section 6.3, the Commission Panel is concerned that productivity is not being optimized. Further, the Panel agrees with the CEC that the balanced scorecard, while tracking O&M per customer, does not adequately measure productivity. The Commission Panel directs that for the next revenue requirements application, the FEU bring forward a benchmarking study that would assess their balanced scorecard against mechanisms used in other peer group companies and jurisdictions. Such an assessment should examine, among other things, the appropriate measurements for productivity and describe what a fulsome set of productivity measurements would entail. Additionally, the Commission Panel believes it would be useful for this study to examine how other members of the FEU's peer group link the use of their performance metrics with the assessment of corporate and individual performance.

7.0 OTHER ADMINISTRATIVE MATTERS

7.1 Reconnection/Reactivation Charges

The FEU propose to increase the reactivation/reconnection fee charged to customers for reinstatement of gas service following a disconnection from $65 (during regular hours) and $105 (after hours) by $35 to $100 (regular hours) and $140 (after hours). This represents an increase of over 50 percent for regular hours and approximately 33 percent for after hours reconnection service. The FEU submit that it is appropriate for the group of customers who have been disconnected and seek reconnection to pay the full cost of their own disconnect/reconnect plus cover the cost of any customers who are disconnected and do not reconnect. There is no lock off/disconnect fee as this tends to be uncollectible at the time of a disconnect. (Exhibit B-62)

The BCOAPO expresses concern with the magnitude of the proposed increases and submits that low and fixed-income customers are more likely to be affected by these fees. BCOAPO submits that any fees should recover the actual disconnect/reconnect charge and no more. BCOAPO suggests that customers who are facing disconnection might also be candidates for various types of assistance programs which may be available and the Utilities may wish to investigate this idea further. (BCOAPO Argument, pp. 16-17)

The FEU maintain that it is equitable that customers requesting the reconnect service should pay for the costs of customers who disconnect without reconnecting, rather than having all customers bear this cost. They also argue that maintaining the spread as between regular hours charges and after hours charges will incent customers to request the reconnect service during regular hours. (FEU Reply, p. 23)

Commission Determination

The Commission Panel agrees with the BCOAPO that the group of customers requesting reconnection should bear the cost of their disconnect/reconnect only, and not those of the customers who do not reconnect and are not charged. The Panel sees little value in saddling these reconnecting customers with additional costs which they have not caused.

We have reviewed the figures provided by the FEU in Exhibit B-59 (Attachments 1-3) which purport to set out the historical costs related to lock offs, unlocks and relights, and relights only and unlocks only. This Table, in the Panel's view is by no means straightforward. While FEU claim they are unable to determine how BCOAPO arrived at the cost figures it used in its argument, the Panel is likewise unable to determine how the FEU derive their figures. The Panel further does not see the need to incent customers from requesting a reconnect service when they may need it most, after hours, when the temperature tends to be lower than during the day. The Panel is also concerned as to the magnitude of the cost increases, representing, as noted above, in excess of 50 percent for regular hours and 33 percent for after hours.

Accordingly, the Commission Panel sets the reconnect fee for regular hours at $90.00 and after hours at $115. These numbers, in the Panel's view, better reflect the cost of the service. The Panel also agrees that the FEU may wish to target customers who have trouble paying their bills for possible EEC or other funding such that a portion of the disconnections historically experienced may be avoided in the future.

7.2 Calculation of Costs for Thermal Energy Services

The FEU submit that they will incur Thermal Energy Services costs in the test period. However, these costs will not impact the rates sought in this Application as the FEU allocate these TES costs to a specific deferral account. (Exhibit B-1-3, p. 16)

The FEU's evidence is that, whether or not a particular TES project proceeds, all costs related to this class of service within the utility will accumulate within the TES deferral account and be recovered from TES customers. This places the risk of non-recovery of the amounts accumulated in the deferral account on the shareholder. (Exhibit B-1,p. 15, Exhibit B-1-3, p. 16, Appendix G pp. 2-5, T5: 778-779)

Currently, the Companies allocate Thermal Energy Services costs into three "buckets"

- Overhead (i.e. the $500,000 annual allocation at issue),
- Sales and marketing, and
- Direct costs which relate to a particular project or projects and may be capitalized as part of project costs.

(T5: 779, 783)

Overhead

The FEU have allocated $500,000 of administrative overhead to FEI's TES Group (formerly Alternative Energy Services) for each year in the test period. These amounts have not changed from the amounts charged in 2010 and 2011. The FEU's calculation of the applicable overhead charge includes a general recognition of expenses from the following categories:

- Executive Time;
- Finance;
- Regulatory Affairs;
- Human Resources;
- Information Technology Support;
- Facilities Costs.

(Exhibit B-1 pp. 275-276; Exhibit B-1, Appendix G, pp. 4-5)

The FEU's evidence is that the overhead allocation of $500,000 "represents the expected administrative costs of supporting the Thermal Energy Services business" and remains appropriate for the test period. (Exhibit B-1, Appendix G, p. 5, T5: 785)

Sales and Marketing

In terms of Sales and Marketing O&M and Business Development, the actual costs of the employees in the TES Group (12 in number) as well as any direct time from other employees in other areas of the Companies and certain contributions to industry associations are accounted for in this "bucket." The costs for this area are in the $1.5 million range. (Exhibit B-1, Appendix G, p. 4)

The FEU advise that the TES Group is now part of the Energy Solutions and External Relations Department of the Utilities. This department comprises 118 employees (as projected to the end of 2011), including the Vice President in charge of the department and the executive assistant. It is divided into five major areas of responsibility:

	Employees
• Corporate Marketing and Communications	(18)
• Energy Solutions	(41)
• Community, Aboriginal and Government Relations	(10)
• Market Development	(40)
• Resource Planning and Market Assessment	(07)

The FEU note that the Market Development group includes 17 employees, the costs for which are included in the Energy Efficiency and Conservation deferral account, and are thus excluded from current period expenses. (Exhibit B-1, pp. 207-208)

Direct Costs

The FEU also track direct costs for items such as feasibility studies, design and construction of various actual thermal energy projects. Projected spending in this bucket has gone from $1.2 million (actual) for 2010 to $11.750 million for 2011. (Exhibit B-1, Appendix G, p. 4, Table G-2) These costs are not included in the forecast costs of the Utilities within this Application but are recorded directly in the TES Deferral Account as they are incurred.

Future of TES

The FEU acknowledge a vast potential for their Thermal Energy Services. They state: “[t]he market 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...”. (Exhibit B-1, Appendix G, p. 2)

The $500,000 per year overhead charge is in addition to the direct costs of the TES Group which are accounted for in the other two “buckets” discussed above.

Intervener Comments

A number of Interveners have taken issue with the $500,000 allocation of costs as well as the methodologies used to capture costs from FEI to allocate to the TES Group.

BCOAPO argues that the overhead allocation amount seems “modest” when compared to the $250 million in potential projects to be developed as set out in the Application. (BCOAPO Final Submission, p. 24, Exhibit B-1, Appendix G, p. 2)

BCOAPO also notes the “structural incentive” to underestimate the amount allocated to TES because TES monies are more at risk. The more that the FEU can leave in the regular utility, the more they are assured of collecting. (BCOAPO Final Submission, p. 24)

ESAC contends that the cross-payment of $500,000 from FEU’s TES business unit to their regular natural gas distribution utility may not be reflective of the actual benefit derived from the corporate association. ESAC notes that the TES business unit has access to the natural gas utility infrastructure, makes use of the utility corporate debt facility and reports to the same Senior Vice President as the ES&ER department of the utility. ESAC also argues that many other departments of the regulated utility support the development of this new business unit and lists: executive leadership, regulatory affairs, legal, customer billing, human resources, and information technology as examples. (ESAC Argument, p. 7)

Corix submits that "identifying and allocating the TES costs is indeed difficult. [The FEU do] not impose any specific restrictions on the sharing of resources. In fact, the widespread sharing of resources is encouraged as a part of the new [FEU] business paradigm." (Footnotes omitted, Corix Argument, p. 3)

Corix observes that prior to 2010, Terasen Inc. offered TES through "TES Inc.," a wholly owned and unregulated subsidiary. This approach was consistent with the Commission's 1997 Retail Markets Downstream of the Meter (RMDM) Guidelines. (Corix Argument, p. 4) As of January 1, 2010, these services have been provided through the FEU. (AES Inquiry, Exhibit B-2, p. 118) Corix argues that the FEU have not attempted to create a distinct separation between the two businesses, but rather, are viewing the business areas as different "classes of service" within the regulated operations, using available resources for the benefit of both classes of service. Corix argues that the TES offerings are more than a new class of service, they are new lines of business. (Corix Argument, p. 6)

The FEU submit that there is no relationship between the size of the cost allocation in the test period and the long-term development of the potential of the TES class of service. They further submit that the $250 million is an estimate of the potential investment which could take years to realize. (FEU Reply, p. 38)

The FEU further take the position that "... typical quantitative methodologies [for allocation of overhead] are not readily applicable in this case because the TES class of service currently has no customers, revenues or assets." The FEU further argue that "[t]he evidence supports the fact that the TES business is only a very small component of FEI's business and uses overhead commensurate with the amount allocated." (FEU Reply, p. 39)

The FEU further submit that charging the Thermal Energy Services class of business with costs which are being incurred by the regular natural gas business, such as long term planning, collection of sales and marketing information, financing capability and advertising is unnecessary, as the use of these services by the Thermal Energy Services class of business does not impact the natural gas revenue requirements. (FEU Reply, pp. 40-43)

The FEU also dispute Corix's allegation that FEU's natural gas "brand" provides value to the TES business that is not captured. The FEU submit that in a cost of service regime, customers do not pay for the use of the utility's brand such that there are no costs to be allocated. (FEU Reply, p. 42)

In evaluating the sufficiency of both the i) overhead and ii) sales and marketing cost allocation methodologies put forward by the Utilities, it is the Commission Panel's view that a number of relevant areas tend to overlap to a greater or lesser extent, not only with each other, but with areas which are directed to new, non-traditional activities. These include: Customer Service, Energy Solutions and External Relations and Marketing and Communications. The overlap is particularly relevant in this Application due to the Companies' proposed venture into a number of different new business areas where there may be competition, and the position taken by a number of Interveners that an insufficient amount has been allocated away from the Utilities to the new business areas.

In terms of operating costs which are not charged to new business areas, but to all non bypass customers, the following departments are noteworthy:

Energy Supply and Resource Development

This group is seeking to add two new business development specialists to its Resource Development Group. This work involves "identifying and developing new regional projects as well as system infrastructure projects." (Exhibit B-1 p. 188) The Panel queries the need for additional business development specialists for the mature gas distribution business, as opposed to the new business areas. The proposed increased expense is discussed and rejected in section 6.4.2.

Customer Service Department

As noted earlier, the Customer Service Department is described in the Application as playing "a vital role in providing service to customers, and consequently represents a core element of the business." (Exhibit B-1 p. 190)

Also as discussed earlier, the Customer Service Department function was for the most part, outsourced to an external provider for a number of years. In June, 2009, the Utilities applied for a CPCN to repatriate their customer service function. The CPCN was granted by Order C-1-10 and the FEU will in January 2012 commence operation of two new Customer Contact Centres, one in the Lower Mainland and the other in Prince George. FEU have described the new in-sourced framework as enabling them "to better meet the current needs of [their] customers, *with the ability to efficiently adapt to customers' needs as they change over time.*" [emphasis added] The Customer Service Department was formerly a division of the "Energy Solutions and External Relations Department" which itself was formerly known as the "Marketing and Business Development Department." (Exhibit B-1 p. 191)

The Customer Service department has a number of Functional Groups including the new Contact Centres, Revenue Cycle and Billing Operations and Customer Relations. The Contact Centres show annual O&M in the $12 million range. These two new Contact Centres, which are pivotal to the new customer service framework, are described in the Application as allowing the Utilities 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.*" (Exhibit B-1 pp. 194-195) [Emphasis Added.]

The Revenue Cycle and Billing Operations area involves annual O&M in the $15 million range. This group will be able to implement "new rate structures as needed," such as natural gas refuelling services for fleet vehicles. In the Panel's view, the capacity to implement new rate structures will be of assistance to the FEU in pursuing new business areas.

The Customer Relations group has an annual O&M budget of approximately $4 million. One of the functions of this group is to secure customer feedback on expectations for existing and *potential new products and services*. (Exhibit B-1 p. 196) [Emphasis Added]

The Corporate Marketing and Communications group has responsibility for internal and external communications strategies and standards and media relations. This group has undertaken initiatives in, among other things, safety education messaging. With respect to education, Mr. Stout testified that it is necessary to "spend a lot of time ... educating and informing people" on the value of natural gas and how it fits in to the energy future. (T5: 808-809)

The Energy Solutions group manages key customer accounts and customer relations. It communicates with customers about service options and new service initiatives including EEC program opportunities.

The Community, Aboriginal and Government Relations group fosters relationships with communities, municipalities, First Nations, business associations, government ministries and other organizations which regulate the energy industry, health and safety, and the environment.
The Market Development group identifies and develops new energy services products such as the Biomethane initiative and NGV fuelling. EEC programs are developed, implemented and tracked by this group which also monitors technological developments and energy policy.

The Resource Planning and Market Assessment group is responsible for forecasts of energy demand and supply and also develops the Companies' Long Term Resource Plan.
The budget for the ES&ER Department has been in the $15 to $16 million range throughout 2010 and 2011. The budget forecasts an increase in spending of over 20 percent to $19 million for 2012 with a further 5.5 percent increase to $20 million for 2013. (Exhibit B-1 p. 209)

Communications Plan

The FEU provided their 2010/2011 "Communications and Public Affairs Plan" dated August 25, 2010 (Communications Plan) in answer to an Information Request from Commission staff. (Exhibit B-17, Attachment 29.1.)

Education concerning natural gas benefits is discussed in the Communications Plan. With respect to the Residential and Commercial Customers stakeholder group, the Communications Plan notes:

> There is still a negative bias within the general public against natural gas as compared to other energy sources such as electricity. Therefore, educational communication needs to be delivered that clearly points out efficiency and emissions benefits to chip away at this negative bias. In addition, natural gas should be positioned as an important part of the new clean energy solution combined with alternative integrated energies such as geoexchange, solar thermal and biogas. By demonstrating natural gas as part of the integrated energy system, the company will achieve a positive halo effect over natural gas and reinforce its leadership positioning in sustainability. (Communications Plan, p. 31)

The Communications Plan notes that the combination of the FEU and FortisBC Inc. under one leadership and a common name provides "a significant opportunity to strengthen the brand." (Communications Plan, p. 5) The Communications Plan also contemplates an ongoing corporate focus on, among other things, community involvement and corporate responsibility. These are viewed as helping to "differentiate the organization and provide a competitive advantage against other energy providers." (Communications Plan, p. 5) This is reiterated at page 11 where it is confirmed that "...an ongoing focus on the customer and the use of high quality service and community involvement [can be used] as a differentiator and competitive advantage versus other energy providers in the province."

The Communications Plan is designed around a single "key brand message," being "FortisBC is leading British Columbia to a sustainable energy future." This statement forms the basis of all communication efforts of the Companies. (Communications Plan, pp. 6, 13)

There are three pillars identified in the Communications Plan:

- Reliability – the critical importance of safety
- Relationships – the value of being a good corporate neighbour
- Readiness – the need to develop sustainable energy solutions to meet our customers' future energy requirements.

The intent of the exercise is to position FortisBC "as a leader in sustainable energy, offering a full spectrum of energy products and services in British Columbia." (Communications Plan, p. 12)

In the Panel's view, the overall branding strategy described in the Communications Plan confirms that there is a major corporate focus on new lines of business which permeates the departments discussed above, among others.

The Communications Plan also identifies various stakeholder groups, one of which is "Policy Makers, Elected Officials (including First Nations), and Bureaucrats." For the Integrated Energy Solutions line of business, the Communications Plan notes the ability of the Companies to finance, own and operate Geo Exchange and District Energy Systems is of key importance to this stakeholder group as the Companies can help them with meeting climate action challenges as well as helping to free up provincial capital for other priorities such as health care. (Communications Plan, pp. 28-29)

Commission Determination

The Commission Panel agrees with the BCOAPO that there is a structural incentive for the FEU to minimize the costs allocated to the TES business because it is at the risk of the shareholder

The Commission Panel also finds that the Companies are sharing resources among lines of business.

It agrees with ESAC that there are many departments within the FEU that contribute to the promotion of new lines of business, not all of which were listed by the FEU as having been recognized in the $500,000 overhead allocation nor are provided for in the direct cost allocation methodology for sales and marketing costs proposed by the FEU.

The Commission Panel disagrees with the FEU that charging the TES class of business with costs which are being incurred by the regular natural gas business, such as long term planning, collection of sales and marketing information, financing capability and advertising is unnecessary, as the use of these services by the TES class of business does not impact the natural gas revenue requirements. (FEU Reply, pp. 40-43) Rather, the Panel is of the view that unless these costs are allocated as between the traditional natural gas business and the new lines of business, the new lines of business may obtain an unfair advantage over competitors, and at the same time natural gas ratepayers may well be overpaying costs which could be shared.

The Commission Panel notes that the FEU strategy is to brand the Companies as leaders into a sustainable energy future, educating stakeholders as to alternative energy options, and committing significant resources to "community involvement" and "corporate responsibility," (with the specific objective of obtaining an advantage over potential competitors identified in the Communication Plan). The Panel further notes that these all serve to ease the Companies into new lines of business and are sought to be to the account of natural gas ratepayers.

In terms of "branding," the Commission Panel specifically disagrees with the FEU's argument that, as customers do not pay for the use of the utility's brand, there should be no allocation to TES. (FEU Reply, p. 42 (f)) The point is not that customers are not paying for the use of the brand but that the FEU's ratepayers are paying for the development of a brand, which the FEU seek to use going forward, at least in part in furtherance of their new lines of business.

In the Commission Panel's view, the allocation of overhead and sales and marketing costs to

Thermal Energy Services is insufficient and therefore the proposed $500 thousand overhead allocation for TES is denied. The departments identified above as overlapping to some extent with each other, have also been used by the FEU to position themselves in furtherance of the new lines of business. Those departments have a combined budget approaching $50 million. The Panel also notes the ten-fold increase in direct project costs charged to TES between 2010 and 2011 as compared to the overhead charge which has remained relatively static over the same period. **The Panel finds that a more reasonable allocation of overhead and sales and marketing costs would be $750,000 for each year of the test period as opposed to the $500,000 now being allocated. This amount would be in addition to the direct sales and marketing costs of the TES group already identified and allocated to the appropriate deferral account by the Utilities.** This increase recognizes that there is uncertainty and judgment involved in allocating overhead costs to a new business area where no formal tracking has been done, but also recognizes the significant increase in activity in support of the Thermal Energy Services area, which, in the Panel's view, has not been adequately recognized. **For future revenue requirements applications, the FEU are directed to propose criteria which can be used to provide a better assessment of an appropriate overhead and sales and marketing cost allocation.**

7.3 Uniform System of Accounts and Budgeting

In 2007, in the 2008 RRA Decision the Commission gave FEI consent to deviate from the Commission's GAS Uniform System of Accounts (USoA) for the purposes of reporting O&M expenses in Accounts 600 to 999 and to prepare reports using the New Code of Accounts, providing both a resource-based view and an activity-view.[20] (Commission Order G-153-07, p. 3, Appendix A) At the time this provision was made, the Commission noted that this approved Code of Accounts was to provide consistent and informative reporting similar to the Commission's USoA for Gas Utilities.

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[20] In the Matter of An Application by Terasen Gas Inc. for Approval of 2008 Revenue Requirements and Delivery Rates; Decision and Order G-153-07 dated December 10, 2007 (2008 RRA Decision)

The FEU were asked to provide O&M costs reported by cost driver, and if that was not possible, by the lowest level of activity code or cost element. (Exhibit B-17, BCUC IR 2.12.4) This request was made to allow for greater understanding of O&M costs and their comparability from 2006 until the current time.

In their response, the FEU state that the data is not available by cost driver and they provide no further detail of costs at an account level, noting that "the more granular the analysis is, the less comparable it becomes due to changes in organizational structure and accounting policies". The FEU further note that the Commission had approved the Companies' Code of Accounts in Order G-153-07 and submit that this level of detail is sufficient. (Exhibit B-17, BCUC IR 2.12.4)

None of the Interveners made submissions on this matter.

Commission Determination

The Commission Panel understands that the FEU's Code of Accounts was approved by the Commission in Order G-153-07. However, the Panel does not believe it is appropriate to relieve the Utilities of the responsibility to report "granular" account level details of their O&M accounts on a comparable basis because it restricts the ability of the Commission to fully analyze the information provided. The Commission Panel finds this particularly relevant given the FEU's move from a PBR to a Cost of Service rate setting mechanism over the 2006-2011 timeframe.

The Commission Panel believes that the use of the USoA for reporting purposes would require consistent and comparable information at an account level. We also note that if forecasting for a future RRA followed this same system of accounts, it would provide further clarity of forecast to actual results at an account level. Given these advantages, the Commission Panel believes there would be considerable benefit to the regulatory process if the FEU were to fully adopt the USoA. In addition, the Commission Panel believes the use of consistent reporting would enhance transparency, comparability and understanding of costs of the FEU as they move forward with new initiatives and projects.

Therefore, the Commission Panel directs the FEU to begin investigating the cost of fully converting to the USoA and to work with Commission staff to develop a plan that will allow the FEU to fully adopt the USoA prior to filing their next RRA with the Commission. A proposed plan for conversion within the timelines presented should be discussed with Commission staff and filed with the Commission no more that 180 days from the date of this Decision. The filing should identify any cost deferral account mechanism needed to facilitate the changeover.

7.4 FEI Southern Crossing Third Party Revenues

As set out in Section 5.5 of the Application, FEI is requesting approval to change, effective January 1, 2012, the methodology for allocating costs and revenues associated with the Southern Crossing Pipeline (SCP) between the MCRA and the delivery margin, and the allocation of the Spectra Energy Kingsvale T-South charges related to the Northwest Natural (NWN) capacity. The change in the allocation methodology is intended to continue to reflect the principle that customers paying for SCP in the delivery margin should share in the mitigation revenue associated with the operation of the SCP and to better reflect current contracts and operational practices. (Exhibit B-1, pp. 295-297)

The SCP third party revenues are forecast at approximately $14.8 million for both 2012 and 2013. The change to the methodology does not impact SCP revenues. The new methodology results in a continuation of the debiting of the MCRA and crediting of the delivery margin in the amount of $3.6 million per year for 2012 and for 2013. (Exhibit B-1, pp. 295-297)

No Interveners took issue or commented on the allocation of SCP costs and revenues.

Commission Determination

The Commission Panel approves the proposed changes in the methodology for allocating SCP costs and revenues between the delivery margin and the MCRA, and the allocation of the Spectra Energy Kingsvale T-South charges related to the NWN capacity. The Panel also approves the continuation of the debiting of the MCRA and the crediting of the delivery margin revenue in the amount of $3.6 million per year for 2012 and 2013.

7.5 Quarterly Reporting of FEVI Gas Cost Variance Account

The FEU have requested a change to the reporting requirements of the FEVI GCVA and the RSDA. Currently, the FEVI forecast gas costs and GCVA must be reported quarterly. Under the 2010-2011 Negotiated Settlement Agreement and, as proposed in the Application, the FEVI rates will remain frozen and not subject to quarterly gas cost flow through adjustments. In Section 6.3 of the Application, FEVI requests approval to discontinue the requirement to provide quarterly reporting on the GCVA and the RSDA on the basis of improved administrative efficiency.

FEVI indicates it is not opposed to reporting the GCVA and RSDA balances on an annual basis as part of the fourth quarter report cycle. In response to BCUC IR 1.109.3, FEVI states that there are no cost savings and only administrative and regulatory efficiencies to be gained by discontinuing the quarterly reporting of the GCVA and RSDA balances. (Exhibit, B-9, BCUC IR 1.109.1-1.09.3; T4: 628, 630) In its Final Submission, FEVI suggests that an alternative that would reduce the regulatory reporting burden would be for FEVI to file quarterly reports that exclude reporting on the customer additions and the comparison to the competitive market. (FEU Final Submission, pp. 152-153)

No Interveners commented or took a position on the FEVI quarterly reporting requirements.

Commission Determination

Given that a process is underway to assess the potential amalgamation of FEVI and FEU, and the minor nature of the administrative costs, the Commission Panel is of the view that it would be of value for FEVI to continue to report gas costs and GCVA balances quarterly. However, in our view it is unnecessary to include in the quarterly report any comparison to electricity or fuel oil prices. **The Commission Panel directs FEVI to continue to report FEVI's forecast gas costs and GCVA balances on a quarterly basis and approves discontinuing quarterly reporting of the customer additions and the comparison to the competitive market.**

8.0 ENERGY EFFICIENCY AND CONSERVATION

8.1 Introduction

The FEU submit an expenditure schedule to section 44.2 of the *Utilities Commission Act* setting out their proposed spending for Energy Efficiency and Conservation. In the Application, the FEU requested EEC expenditures of $74.5 million for each of 2012 and 2013. This request was subsequently amended to $64.5 million for 2012 and 2013 following the release of the EEC NGV Incentives Decision.[21] The amended request reflects a $10 million reduction in forecast NGV incentive payments. (Exhibit B-1, p. 393, Exhibit B-1-3, p. 393)

The current request for EEC funding is broken down into two sections: Existing Program Areas and New Initiative Program Areas. Existing Program Areas, with requested funds of $38.3 million in 2012 and $38.2 million in 2013, encompass Residential, High Carbon Fuel Switching, Low Income, Commercial, Conservation Education and Outreach, Industrial and Innovative Technology Program Areas. New Initiative Program Areas encompass three Program Areas, Furnace Scrap-it, Solar Thermal Program and Thermal Energy Services for Schools. The funds requested for these new Program Areas were originally $25 million in both 2012 and 2013, but the FEU agreed to a reduced amount for Solar Thermal and Thermal Energy Services for Schools due to the lack of specifics presented for each of these program (T9: 1487, 1450)

In addition to the funding requests for the various Program Areas, the FEU has sought approval on a number of other matters in the Application including the creation of a dollar threshold for inclusion in rate base, the expansion of certain programs to all customers, the inclusion of spillover, and the retention of the current framework governing the EEC portfolio.

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[21] In the Matter of FortisBC Energy Inc. and Fortis BC (Vancouver Island) Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review; Decision and Order G-145-11 dated August 15, 2011 (EEC NGV Incentives Review Decision)

The FEU also requested further changes involving use of the Societal Cost Test. This was later withdrawn following amendments to the *Demand Side Measures Regulation* made pursuant to Ministerial Order 335.

In the following Sections the Commission Panel will first examine the EEC programs and funds requested and provide direction as to the funding amounts which are to be approved for the 2012/2013 test period. The Commission Panel will then discuss issues that have arisen in this Proceeding: the impact of requested expenditures on future rates, examine the remaining requests from the Application, and close with a discussion of the issue of structural tension which was raised by the BCOAPO in its Final Submissions.

8.2 EEC Expenditures – Legal Framework

As noted earlier, expenditures on demand-side measures are subject to a different legal framework than revenue requirements generally.

Before the Commission can approve final rates which recover demand-side measures expenditures, the Commission must have accepted an expenditure schedule filed by the utility containing a statement of the demand-side measures the utility has made or anticipates making during the period covered by the schedule. (*Utilities Commission Act*, ss. 44.2 (1) (a), ss. 44.2 (2)*)*

In making its decision as to whether to accept such an expenditure schedule filed by a public utility other than BC Hydro, the Commission must consider:

(a) The applicable British Columbia energy objectives (as set out in the *Clean Energy Act*);

(b) The most recent long-term resource plan filed by the public utility under s. 44.1, if any;

(c) The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;

(d) Whether expenditures on demand-side measures are cost-effective within the meaning prescribed by regulation; and

(e) The interests of persons in British Columbia who receive or may receive service from the public utility.

(*Utilities Commission Act*, s. 44(5))

The applicable British Columbia energy objectives relating to demand-side measures (DSM) include, or may include, in the Panel's view, the following objectives referred to in Section 2 of the *Clean Energy Act:*

b) to take demand-side measures and to conserve energy...

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,

g) to reduce BC greenhouse gas emissions...

Other objectives which may be relevant to expenditures the FEU propose to make include or may include:

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,

k) to encourage economic development and the creation and retention of jobs

The FEU submit that their most recent Long Term Resource Plan filed in 2010 laid the foundation for the further analysis contained in the Conservation Potential Review filed with this Application in support of the proposed EEC portfolio. (FEU Final Argument, p. 180) The Commission Panel is of the view that the 2010 LTRP is not inconsistent with the EEC portfolio proposed in this Application

Sections 6 and 19 of the *Clean Energy Act* are not relevant to this Application.

The test for cost-effectiveness for a demand-side measure was modified by Ministerial Order 335 dated December 8, 2011. This Ministerial Order attached a Schedule which amended the Demand-Side Measures Regulation (BC Reg. 326/2008) in a number of areas. Section 1 of the Schedule defines clean or renewable resource as having the same meaning as in the *Clean Energy Act*, i.e. biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. Section 2 of the Schedule modified the total resource cost test and its application to, among other things, set the avoided cost of natural gas to the avoided capacity cost plus one half of BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia. The amendments to the *Demand-Side Measures Regulation* found in Section 2 of the Schedule also increase the benefits associated with a demand-side measure by a minimum of 15 percent, subject to the expenditure portfolio containing only one third of demand-side measures which would not be cost-effective without the 15 percent adder. The modified total resource cost test is referred to as the MTRC in this Decision.

The FEU made a submission on the impacts of the amendments to the DSM *Regulation* with respect to whether the demand-side measures are cost effective as prescribed by regulation. They submit that the cost-effectiveness test results for all previously approved Program Areas and all three New Initiative Program Areas have an MTRC of 1.90 and a Utility Cost Test (UCT) of 2.34. (Exhibit B-92, p. 7) The FEU therefore submit that their total EEC portfolio is cost-effective as prescribed by regulation. The only individual existing program that fails the MTRC is the Energy Conservation Assistance Program (ECAP) in the Low Income Program Area. BCSEA and BCOAPO both support the ECAP program which the FEU submit should be accepted because the overall portfolio is cost effective. (Exhibit B-92, para. 10, BCOAPO Final Submission, p. 34, BCSEA Final Submission p. 8)

8.3 EEC Deferral Account Approvals

The FEU are seeking approval to amortize EEC expenditures over a ten year period. This is the same amortization period approved in the Terasen 2009 Energy and Efficiency Conservation Decision. At that time Terasen was advocating a 20 year amortization period on the basis that the average period of time over which ratepayers benefited from the EEC expenditures was 22.5 years. The Commission at that time found the benefit forecasts were too uncertain to give them any weight.

BCOAPO has proposed that the actual expected useful life of a demand-side measure should be used rather than the blanket 10-year amortization period. (BCOAPO Final Submission pp. 34- 35)

The FEU have also proposed that $15 million (adjusted downward from the original proposal of $20 million) of the total requested amount of $64.5 million be added to the EEC rate base deferral account in 2012 and 2013 on a net-of-tax basis. Flowing from this is the Company's proposal to create an EEC Non-Rate Base Deferral Account, attracting AFUDC, to capture any additional EEC costs as incurred on an actual spend basis in 2012 and 2013. This would be held to a maximum of $49.5 million per year (representing the total spend request less the $15 million addition to the Rate Base Deferral Account), to be recovered over a ten year period with the method of recovery determined in the next revenue requirement in 2014. The FEU further propose that the 2012 and 2013 non-incentive costs accumulating in the EEC Rate Base Deferral Accounts be allocated among the Companies on an average number of customer basis which will result in an approximate split of 89 percent to Mainland, 10 percent to Vancouver Island, and 1 percent to Whistler. Incentive costs are proposed to be allocated on an as spent basis. (Exhibit B-1-3, pp. 392-393, FEU Final Submission, p. 199)

The Companies have proposed including $15 million in the rate base deferral account rather than the total requested EEC expenditures as a means of protecting customers from paying in rates for 2012 and 2013 proposed expenditures which are not made. (Exhibit B-1-3, pp. 394-395) The FEU acknowledge that this proposal is in direct response to EEC underspending in 2010 and 2011. As a result of this underspending, ratepayers paid additional amounts in rates reflecting the weighted average cost of capital on the larger expenditure forecast rather than actual EEC expenditures. The $15 million threshold proposed is in keeping with FEU's actual 2011 expenditures of $15.5 million. The FEU further argue that they have learned from the past two years such that they are better positioned in 2012 and 2013 to spend EEC funds. (FEU Reply, p. 197-198)

BCSEA is in support of the FEU's proposed financial treatment and notes its agreement with the Companies' submissions that the treatment will ensure there is a reasonable amount of the EEC expenditure recovered in rates while making accommodation for any under spending of EEC approved amounts. (BCSEA Final Submission, p. 10)

CEC submits that the FEU's proposed two tier strategy for financial treatment is acceptable, as is the $15 million threshold. (CEC Final Submission, p. 48)

Commission Determination

The Commission Panel is satisfied that the proposal for $15 million on a net of tax basis to be added to an EEC Rate Base Deferral account in both 2012 and 2013 is in the public interest. The FEU have been ramping up their EEC expenditures over the past two years as programs are implemented and begin to take hold. This is expected to continue into the current test period and there is no evidence to suggest that an amount less than the proposed $15 million is likely to be spent. The Panel has considered the proposal to create an EEC Non-Rate Base deferral account to capture the remaining portion of the EEC costs to a maximum of the approved EEC expenditure amount less the $15 million threshold to be recovered over a ten year period with the method of recovery to be determined as part of the next revenue requirements. We are satisfied that the methodology will allow all applicable costs to be captured and at the same time protect the interests of ratepayers by keeping the majority of forecast costs out of rates until the expenditures have been made.

As noted later in Section 8.7.4 in this Decision, the Commission Panel and some of the Interveners concerned with how best to amortize these expenditures and over what term. The Panel is not persuaded that a ten-year amortization period is necessarily appropriate but the issue was not canvassed thoroughly enough in this Proceeding to warrant a change. **To assist in understanding this issue, the FEU are directed to provide a report detailing the rate impact of a number of amortization scenarios which will be helpful in determining a long term solution. For the 2012/2013 test period, the Commission Panel is satisfied that the proposed 10-year amortization period for the rate base deferral account is reasonable as is the FEU's proposal to allocate costs based upon the average number of customers served by each Company. Accordingly, the Commission Panel approves the following:**

1. **EEC rate base additions of $15 million in both 2012 and 2013 to be included on a net-of-tax basis and amortized in rates over a 10-year period.**

2. **The allocation of the 2012 and 2013 EEC rate base deferral account non-incentive additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler.**

3. **The allocation of 2012 and 2013 EEC incentive costs on an as incurred basis.**

4. **The creation of an EEC Non-Rate Base deferral account, attracting AFUDC, to capture the additional EEC costs as incurred on an actual spend basis to a maximum of the total approved EEC expenditures less $15 million in 2012 and 2013. No determination on amortization rates will be made at this time.**

8.4 Past Performance

In 2011 and 2012 the implementation and related expenditures on EEC programs were far less than what had been expected. Table 8.1 outlines the number of dollars spent or forecast to be spent in 2011 as compared to the amounts approved by the Commission as well as the cost of this underspend to ratepayers.

Table 8.1

EEC Expenditures
2012 and 2012

	2010		2011	
	Approved	**Spent**	**Approved**	**Forecast to be Spent**
$ (000s)	31,049	10,000	35,300	15,541
% spent of approved	32.2%		52.5%	
Equity Return on unspent funds $ (000s)	426		981	

(Source: Exhibit B-73, Undertaking 40, Exhibit B-1-3, p. 11, Exhibit B-17, BCUC IR 2.90.1, Table 2, T9: 1457)

Total expenditures over the two-year period were only slightly greater than 38 percent of the $66.3 million in funds which had been approved. Since the approved amounts were included in rate base, the FEU earned a return on the full forecasted amount. The impact of this unspent balance was that ratepayers collectively were required to pay $1.407 million more than they ought to have paid. The EEC Non Rate Base Deferral Account approved in the previous section will prevent this from happening in 2012 and 2013.

The FEU have submitted a number of reasons to explain the under spending which occurred in both 2010 and 2011. The most important among these are the following:

- Human Resourcing Issues

The total amount of DSM funding approved for 2010 was a significant increase over 2009 approved levels of approximately $4.5 million. The FEU submit that they added human resources over the summer of 2009 and again in the spring/summer of 2010 to work on the design, development and implementation of an expanded range of programs made possible by this increase in funding. The Companies explain that the required expertise was not readily available in the marketplace which resulted in their having to train most of their new human resources on both the natural gas business and EEC. The FEU explain that this time-consuming process delayed new program development and implementation.

- Economic Factors

The FEU assert that the combination of the financial crisis starting in 2007 and changes in government leadership had an impact on the level of customer focus on EEC activities. Commercial customers were constrained by tighter access to credit and it was more difficult to get them to spend funds on EEC measures. Similarly, there were challenges with residential customers who were concerned about their employment leading to reduced customer activity in EEC programs. Finally, the FEU note that the change in the leadership of both provincial political parties had an effect on the level of certainty of customers with respect to government demand-side management programs like those of LiveSmartBC.

- Low Cost of Gas Commodity

The low cost of natural gas and its impact on rates was discussed in Section 4.1. The FEU submit that there was greater difficulty focusing the attention of the customer on energy efficiency and conservation when the commodity cost was so low.

The FEU's answer to low participation in individual EEC programs due to lower gas prices is to offer more program options in the marketplace. Further, the Companies acknowledge that the human resource issue discussed above continues to be very much a key factor limiting customer participation.

The FEU have expressed the view that the financial crisis is easing to the point where customers are willing to spend more on EEC. They submit that the development of more programs and initiatives, made possible by increased funding approval levels, will lead to greater customer participation in these programs. As a result, the FEU have stated that “actual spending levels should meet approved expenditure levels.” When asked to provide evidence supporting the change in consumer behaviour related to the improving economy, the FEU conceded there were no surveys pointing to a change in attitude related to customer spending on these types of programs. However, the Companies were able to provide an excerpt from “Canada’s Economic Action Plan” (published in January 2011 by the Canadian Federal Ministry of Finance) supporting the view that the economy is recovering and the level of employment is improving. (Exhibit B-9, BCUC IR 1.192.1, Exhibit B-17, BCUC IR 2.91.1, 2.91.2)

Commission Panel Discussion

Given the magnitude and scope of the expanded EEC programs, the Commission Panel is not surprised that the FEU had difficulties developing and executing them over the relatively short two year test period. Because of this, we accept that the under expenditures were a consequence of the challenges the Companies have faced with respect to a weak economy, the lack of available EEC trained human resources and the difficulty in stimulating customer interest at a time when natural gas commodity costs are very low. However, the Panel would like to point out there has not been a substantial amount of evidence put forward by the Applicants to indicate there has been a significant change in these circumstances. While we acknowledge that there is evidence to suggest the economy is improving, there have been no submissions supporting the view that it will be any easier getting the right people in place in the future. Additionally, as outlined in Section 4.1, the cost of gas has continued to fall. Therefore, the Commission Panel is not persuaded that it will be substantially easier for the FEU to develop, implement and manage programs in the 2012 and 2013 test period. The Panel will give weight to the continued challenges of hiring and training staff and the impact on customer uptake as a result of the low cost of the natural gas commodity as we examine the requested EEC amounts in this Proceeding.

8.5 EEC Expenditure Request for 2013-2014

As noted previously, the FEU have requested approval of $64.5 million in funds for both 2012 and 2013 in the Updated Application. This included a list of planned expenditures for Program Areas as outlined in Table 8.2.

Table 8.2

2012/2013 Requested EEC Expenditures by Program

		Requested Expenditures ($000s)	
		Year	
Existing Program Areas	**Program Area**	**2012**	**2013**
	Residential	9,514	9,484
	High Carbon Fuel Switching	630	630
	Low Income	4,969	4,969
	Commercial	14,520	14,500
	Conservation Education and Outreach	5,000	5,000
	Industrial	2,098	2,098
	Innovative Technologies	1,546	1,502
New Initiatives	Furnace Scrap-it	10,000	10,000
	Solar Thermal	<4,000*	<4,000*
	Thermal Energy for Schools	<11,000*	<11,000*

*The requests for the Solar Thermal Program Area and the Thermal Energy for Schools Program Area were reduced at the Oral Hearing (T: 1450, 1487)

(Exhibit B-25, Appendix 1, p. 5 and Exhibit B-1-3, Updated p. 393)

Program Areas have been separated into two broad categories:

- Existing Program Areas

These include seven separate Program Areas: Residential, High Carbon Fuel Switching, Low Income, Commercial, Conservation Education and Outreach, Industrial and Innovative Technologies. Within each of these Program Areas are existing programs which are currently active and new programs (including programs with substantial new elements).

- New Initiatives Program Areas

The New Initiatives Program Areas include the following: Furnace Scrap-It, Solar Thermal and Thermal Energy for Schools.

8.5.1 Existing Program Areas

As outlined previously, Existing Program areas are broken down into two categories: currently active programs and new programs. The Commission Panel would like to point out that the new programs have been distinguished from the balance of existing programs to facilitate our review.

i) Existing Program Areas - Currently Active Programs

As outlined in Table 8.3, the total dollars requested for programs which are currently active are \$21.78 million in 2012 and \$21.81 million in 2013. Based on the forecast spend for 2011 of \$15.541, this represents an increase of approximately 40 percent in 2012 with virtually no further increase in 2013.

TABLE 8.3

Funding for Currently Active Programs

	Requested Funds for Currently Active Programs in Existing Program Areas	
	($000s)	
Program Area	**2012**	**2013**
Residential	5,759	5,179
High Carbon Fuel Switching	630	630
Low Income	4,969	4,969
Commercial	4,917	5,538
Industrial	388	388
Innovative Technologies	1,546	1,502
Subtotal	18,209	18,206
Conservation Education and Outreach	3,575	3,605
Total	**21,784**	**21,811**

(Source: Exhibit B-25, Appendix 1)

The FEU justify their increased EEC expenditures citing a number of factors. Firstly, there is a request to expand the EEC program to the FEW and Fort Nelson service areas. The cost for these additions has not been quantified. Secondly, the increase requested is a reflection of the FEU gaining greater traction in the marketplace which will result in increased customer take-up. The Companies argue that 2010 and 2011 were the first two full years of the FEU's expanded EEC portfolio but assert that they are better positioned in 2012 and 2013 to spend the approved funds. This is because they now have experienced staff, continuing programs from previous years, the economy is showing signs of recovery, there is more potential for natural gas prices to go up rather than down and there is more political stability in the province. (FEU Final Submission, pp. 197-202)

As noted previously, the Commission Panel has chosen to separate new programs within the Existing Program Areas as a means of facilitating the review process. No such distinction was made by the Interveners. Therefore, the discussion of Intervener submissions which follows, applies to the total Existing Program Area EEC funding request.

Intervener Submissions

BCSEA submits that the proposed funding level of $39.5-million per year for 2012 and 2013 for Existing Program Areas is in the public interest and should be accepted by the Commission. Its expert witness, Mr. Plunkett stated in his evidence that the FEU's proposed spending is in the high end but within the range of DSM investment of their peers. (BCSEA Final Submission, p. 10, and Exhibit C4-4, p. 8)

BCOAPO is generally supportive of EEC spending because well designed DSM should save ratepayers money by reducing their energy consumption. (BCOAPO Final Submission, pp. 33, 35)

CEC agrees that the evidence is supportive of existing EEC program funding levels. (CEC Final Submission, p. 49)

Commission Panel Discussion

i) Conservation Education and Outreach Program Area

An item of concern to the Commission Panel within the Existing Program Areas is the requested increase in spending for Conservation Education and Outreach (CEO). In 2011 the FEU forecast to spend $2.17 million of the $3.5 million approved for the CEO Program Area. (Exhibit B-67, BCUC IR 3.3.2, Attachment 3.2, p. 2) For 2012 and 2013, the FEU have requested funds of $3.575 in 2012 and $3.625 in 2013 to support existing programs which are currently active.

designed to foster a conservation culture within the province through education of customers and changing their awareness and behaviours with respect to conserving energy. (Exhibit B-25, Appendix 1, p. 25) The programs within the CEO Program Area include outreach at home shows and community events, promotions and support to builders' associations, partnerships with local sports teams such as the Vancouver Canucks and the BC Lions and programs in grade and post-secondary schools. (Exhibit B-25, Appendix 1, pp.45-6; Exhibit B-67, BCUC IR 3.1)

The Commission Panel notes that both BC Hydro and FortisBC Inc. also provide general conservation education and community education programs. The FEU report they have collaborated with both utilities on some programs and are seeking further opportunities to work with BC Hydro. (Exhibit B-67, BCUC IR 3.20.3, 3.20.5)

The FEU were asked to discuss the efficiencies and effectiveness of a mass education joint campaign with other utilities or LiveSmartBC versus a campaign run solely by the Companies. In response, the FEU state that results of a preliminary study they had commissioned showed that many consumers view the overall energy conservation message from utilities as being the same. They also state that the study, along with discussions with customers at outreach events, indicate that there is potential for customer and public misconception as to why an investor-owned utility would want to reduce the consumption of its product. The FEU report this led them to believe there is a need for greater education on managing natural gas efficiency as it affects peak usage. Additionally, the Companies note that "as the equipment and most end uses for gas and electricity are different, each utility will have different energy conservation priorities." (Exhibit B-67, BCUC IR 3.20.5, 3.21.2)

BCSEA supports FEU's inclusion of enabling activities (including CEO costs) but does not take a position on the amount of funding for this Program Area. (BCSEA Final Submission, p. 10) No other Intervener provided submissions specifically on the CEO Program Area expenditures.

Commission Determination

The Commission Panel believes there is significant potential for all of the British Columbia utilities to work together to provide coordinated CEO programs and campaigns. We also believe that the concerns raised by the FEU with respect to the potential for public misconceptions and differing energy priorities among the gas and electric utilities can be overcome if there is a will to do so. In creating the desired conservation culture, the Commission Panel believes it is important to reach as many British Columbians as possible and to promote an overall conservation message with less regard to maintaining or promoting a utility brand and to do so using the combined resources of all the utilities. **Therefore, the Commission Panel directs the FEU to take greater advantage of opportunities to collaborate with other utilities with respect to CEO campaigns and communications. In pursuing a more collaborative approach to these types of programs, we believe that there will be savings and available funds can be more effectively used. Accordingly, the Commission Panel approves a reduced amount totalling $2.9 million for both 2012 and 2013 for Existing CEO programs which are currently active.**

ii) Switch and Shrink Programs

The FEU offer the Switch and Shrink program in their High Carbon Fuel Switching Program Area. This program is aimed at incenting customers on Vancouver Island to switch from their current higher GHG emitting heat sources to natural gas, which has fewer GHG emissions.

The CEC suggests that the Commission's findings in the EEC NGV Incentives Review Decision[22] (Commission Order G-145-11) must be reconciled with the previous Commission approvals of the High Carbon Fuel Switching Program Area. (CEC Final Submission, p. 46)

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[22] In the Matter of Terasen Energy (Vancouver Island) Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review; Decision and Order G-145-11 dated August 15, 2011 (EEC NGV Incentives Review Decision)

The FEU submit that, while the EEC NGV Incentives Review Decision made comments concerning load building, the Panel did not determine that load building programs cannot be demand-side measures. The FEU further submit that switching from heating oil and propane using old equipment to natural gas with a high-efficiency furnace is more efficient, in contrast to the Commission's finding in the EEC NGV Incentives Review Decision that NGVs are not more efficient than using gasoline, and that the programs can be distinguished on that basis. (FEU Reply Submission, p. 49)

Commission Determination

Despite the argument set out above, the FEU presented no evidence that heating oil and propane are, in fact, less efficient as fuels than natural gas. The FEU have not presented evidence or argument that persuades the Commission that the fuel-switching programs they offer, which are also load building, meet the definition of a demand-side measure as contemplated in the *CEA* and *UCA*.

The Panel notes the contemplated use of demand-side measures in subsection 44.1 (2) of the *Utilities Commission Act*. That subsection requires a public utility to file a long-term resource plan including not only an estimate of the demand for energy the public utility expects to meet, but also a plan of how the public utility intends to reduce that demand by taking cost-effective demand-side measures. The demand for energy, in this case, is the demand for natural gas, not the demand for other heating fuels, and the demand for natural gas is to be reduced through the use of demand-side measures.

Accordingly, and in keeping with the logic of the EEC NGV Incentives Review Decision,[23] the Commission finds that load building programs should be maintained separate and distinct from load-reducing DSM programs and, as load-building programs provide a financial benefit to FEU

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[23] In the Matter of Terasen Energy (Vancouver Island) Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review; Decision and Order G-145-11 dated August 15, 2011 (EEC NGV Incentives Review Decision)

from the increased load, should not earn the approved Return on Equity that other DSM expenditures earn.

The FEU submit that if the Commission were to determine that the high carbon fuel switching program is not a demand-side measure, it would be appropriate to capture the costs of the program in a deferral account and to determine recovery of those costs in the next RRA. (FEU Reply Submission, p. 50)

The Commission Panel disagrees with this approach. As stated above, the Panel prefers to treat approved load building activities as current period expenses. The Panel accepts the merits of this program and therefore approves FEU to recover the EEC funds forecast to be spent on the Switch and Shrink program as expenses in this RRA.

The Commission Panel also confirms its direction that only expenditures which meet the strict definition of "demand-side measures" as found in the *CEA* and the *UCA* and as determined by the Panel in the EEC NGV Incentives Review Decision are to be included in the category of "EEC" expenditures. Other expenditures are to be classified separately.

iii) Balance of Existing Program Areas

With respect to the remaining Existing Program Areas, the Commission Panel is supportive of the FEU's EEC portfolio and its contribution to reduced energy consumption and reduced GHG emissions. The Panel acknowledges that the FEU have been on a steep learning curve since their EEC expenditure allowance was expanded in 2009 and have made strides to overcome the associated challenges. However, as discussed previously, the Panel believes that opportunities exist to more effectively co-ordinate programs and to design incentives to maximize energy savings.

The Commission Panel approves the requested expenditures of $18.209 million in 2012 and $18.206 million in 2013 for Existing Program Areas (excepting CEO Programs) which are currently active. The Commission Panel considers these estimates for future uptake of existing programs as being reasonable given the program growth which has already occurred between 2010 and 2011 (approximately 55 percent). We also agree with the FEU that there are factors, including an improving economy and the FEU having gained relevant experience which will lead to the EEC gaining greater traction in the marketplace. Moreover, the Commission Panel notes the changes in financial treatment which have been applied for by the FEU and approved by the Commission in Section 8.3. These should ensure that the ratepayer is not unfairly charged over the test period if all the proposed expenditures fail to materialize as planned.

iv) Existing Programs Areas – New Programs

As outlined in Table 8.4, the requested amounts for new programs within the Existing Program Areas are $16.495 million in 2012 and $16.373 million in 2013.

Table 8.4

Existing Program Areas – New Programs

	Program	**2012 Request**	**2013 Request**
		$(000s)	
Residential	ENERGY STAR® Domestic Hot Water "DHW" Technologies – Condensing Water Heaters and Tankless Water Heaters	1,786	1,786
	ENERGY STAR® Washers and Other Measures for DHW Conservation	525	525
	Customer Engagement Tool for Conservation Behaviour	500	1,050
	New Construction – EnerGuide for Homes (80 & beyond) Efficient Appliances	945	945
Commercial	Commercial Custom Design Program	6,383	4,722
	Continuous Optimization Program	2,062	2,812
	Commercial Kitchens Program	70	94
	MURB Program	499	744
	Process Heat Program	590	590
Industrial	Industrial Technology Retrofit Program - Lime Kiln Chain System Upgrade Program	1,710	1,710
	Subtotal	15,070	14,978
Conservation Education and Outreach	Residential Mass Education on Conservation and Energy Literacy	655	655
	Medium-Large Commercial Education Sessions	70	70
	Home Efficiency Measures	450	470
	Behaviour Programs – Energy Specialists	200	200
	School Programs: Class and Online Curriculum	50	0
	Total	**16,495**	**16,373**

(Source: Exhibit B-67, BCUC IR 3.1.2, Exhibit B-25, Appendix 1, pp. 8, 29, 47-49, 69)

The Commission Panel accepts that as the EEC portfolio continues to evolve, there will be a need for additional funds to support the development of new programs. As noted in Section 8.4, the FEU have submitted that the development of more programs will result in greater customer participation. The Commission Panel agrees with this as the introduction of new programs increases the likelihood that more customers will have exposure to energy saving opportunities and, when incented to make an energy efficient choice, will often do so.

However, the Commission Panel is concerned that the FEU are trying to move too far too fast and, in doing so, run the risk of creating problems which could otherwise be avoided. The lesson to be taken from the experience of 2010 and 2011 is that, despite best efforts to get new people in place to develop and implement new programs, the job will not be an easy one and will take time to complete. Moreover, the current low price of natural gas combined with the impact of a slow economic recovery may impact the capability of the Companies to gain the focus of customers on energy efficiency activities making the job of gaining customer acceptance of new programs in the marketplace more difficult. The Commission Panel believes that there will continue to be significant challenges for the FEU in the 2012 and 2013 test period. **Given these concerns and the fact that this Decision is being made at the end of the first quarter of 2012, the Commission Panel approves 40 percent or $6.598 million of the requested expenditures for new programs in Existing Program Areas in 2012 and 80 percent or $13.098 million of requested expenditures for 2013.** The Commission Panel observes that once these amounts are approved, the process of hiring and training additional staff will begin and based on the experience of 2010 and 2011, this could take a significant amount of time. Given this, the approval of 40 percent or $6.598 million of applied for funds should be sufficient to handle 2012 expenditure requirements. Further, based on customer participation over the past two years along with the challenge of getting new programs up and running, the Panel believes that 80 percent or $13.098 million of applied for funds in 2013 will be sufficient to handle expenditure requirements.

8.5.2 New Initiative Program Areas

The FEU have requested approval of $25 million per year for the three New Initiative Program Areas. However, they indicated they were open to an unspecified reduction in the amounts for the Solar Thermal and Thermal Energy for Schools Programs Areas during the Oral hearing (T9: 1487-8, 1490). The requested amount for the New Initiatives, by Program Area is listed in Table 8.5.

Table 8.5
Summary of New Initiatives

Program Area	2012 Request	2013 Request
	$ 000s	
Furnace Scrap-it	10,000	10,000
Solar Thermal	<4,000	<4,000
Thermal Energy for Schools	<11,000	<11,000
Total	**<25,000**	**<25,000**

(Source: Exhibit B-1, Appendix K-1, p.3, T9: 1487-8, 1490)

The FEU have applied for these New Initiatives as three separate Program Areas rather than programs within existing Program Areas. (T9: 1464)

The FEU have not developed program plans for these three new Program Areas because "the Companies would prefer to focus their EEC resources on developing programs within Program Areas for which they have received funding approval." Therefore, detailed program budgets and projections for the New Initiatives have not yet been developed. Anticipated program results based on the Companies' best estimates for these New Initiatives were presented in the response to BCUC IR 1.201.1.1. Should the New Initiatives be approved, the Companies would then allocate resources toward developing the New Initiatives, including gathering and incorporating feedback from interested stakeholders, likely through the EEC Stakeholder group. (Exhibit B-70, Corix IR 3.1.2) As a result, the Commission has only a funding request and high level information in evidence for these three new Program Areas.

The Furnace Scrap-it program was examined in the FEU's 2010 Conservation Potential Review but the Thermal Energy for Schools and Solar Thermal Program Areas were not included in that study of market conservation potential. (T9: 1461) With respect to the Furnace Scrap-it program, the Companies submit they were able to provide preliminary program details for discussion purposes only as they have yet to research best practices from other jurisdictions that run furnace early retirement programs. (Exhibit B-9, BCUC IR 1.202.3, T9: 1464) The FEU have indicated a level of experience with this type of program as they ran an ENERGY STAR Heating System Upgrade program in 2008-2009 in partnership with LiveSmartBC which was a similar to the one proposed. (T9: 1465)

BCSEA's expert witness, Mr. Plunkett, was questioned as to his view on whether the Commission should approve or accept expenditures related to the three New Initiatives without further information in a compliance report. Mr. Plunkett recommended that the Commission authorize the FEU to proceed with the detailed planning but that "it would be in the best interests of everyone for the Commission to see those details and approve them and authorize them, especially regarding how much gas are you going to save from these measures." (T8: 1255, 1258)

Commission Determination

After a review of the evidence, the Commission Panel finds that there has been insufficient evidence provided to justify approval of the New Initiative Program Areas put forward in the Application. The $25 million of proposed expenditures exceeds by a significant margin the total spending on EEC that occurred in 2010 and 2011. Because of the magnitude of the expenditures being proposed, the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest. The Panel notes that the financial treatment approved in Section 8.3 of this Decision allows for EEC Expenditures in excess of $15 million to be captured in a Non-Rate Base deferral account attracting AFUDC. Given this methodology, the FEU could bring forward during the test period a well developed proposal for one or more of these New Initiatives. If acceptable to the Commission, the program could be approved at that time, with the costs going into the deferral account. This would allow the programs to proceed with no requirement to amend rates during the test period.

The Commission Panel rejects the expenditures proposed for the Solar Thermal Program Area and the Thermal Energy for Schools Program Area.

The Panel notes that the FEU provided the Commission with more detail related to the Furnace Scrap-it program than it did the Solar Thermal and Thermal Energy for Schools Program Areas. Moreover, the FEU have experience running a similar program. In the view of the Panel, the information provided, while more robust, was inadequate to support the proposed yearly expenditure of $10 million for the test period. **For this reason the Commission Panel also rejects the expenditure of $10 million annually for the Furnace Scrap-it program in 2012 and 2013.**

However, the Commission Panel believes that the Furnace Scrap-it program has potential and approves expenditures of $2 million for each of 2012 and 2013 for the Furnace Scrap-it program. Part of the $2 million in approved funds is to be used during the test period to develop a comprehensive program plan. The Panel expects the plan to incorporate best practices from other programs that have been run in the province and in other jurisdictions and to take into account related programs that may be offered by other utilities. Given the magnitude of expenditures for this program, the Commission Panel encourages the FEU to undertake further research, perhaps through a pilot program, to determine the most effective form of program design. This should include an examination of what level of incentive will provide the most cost effective results, a more refined estimate of the likely take-up of the program and the optimal means of delivering the program. In addition to offering this as an in-house program, the Panel urges the FEU to consider a joint initiative with LiveSmartBC.

The Commission Panel notes that the FEU have presented no evidence as to why the Furnace Scrap-it program should be a stand-alone Program Area. **Accordingly, the Commission Panel directs the FEU to include the Furnace Scrap-it program under its Residential Program Area.**

8.5.3 Summary of s. 44.2 Expenditure Approval

In summary, the Commission Panel approves EEC and other expenditures for the 2012 and 2013 test period as outlined in Table 8.6 below.

Table 8.6
Commission Panel Approval Summary

		Approved Expenditures	
		($000s) Year	
	Program Area	**2012**	**2013**
Existing Program Areas	Residential, including Furnace Scrap-it program	9,261	10,623
	High Carbon Fuel Switching (non EEC)	630*	630*
	Low Income	4,969	4,969
	Commercial	8,759	12,708
	Conservation Education and Outreach	3,470	4,016
	Industrial	1,072	1,756
	Innovative Technologies	1,546	1,502
	TOTAL	$29,707	$36,204

* to be recovered as expenses (not to be added to rate base)

8.6 Other Approvals Sought

In addition to expenditures, the FEU seek approval of the following requests:

1. Expansion of programs to interruptible industrial, Fort Nelson, and FEW customers;
2. The inclusion of spillover effects in the calculation of the net-to-gross ratio when estimating program energy savings; and
3. The retention of existing elements of the EEC framework such as the evaluation of EEC expenditures as an overall portfolio with the Innovative Technologies Program Area having a separate Total Resource Cost test ratio of 1.0 or greater.

The Commission Panel assesses these requests below.

8.6.1 Expansion of Programs to Interruptible Industrial Customers and to FEW and Fort Nelson

The FEU have requested approval to extend their Industrial programs to interruptible industrial customers because they have an Industrial EEC Manager in place and have developed an industrial strategy. (Exhibit B-1, Appendix K-1, p. 17)

The FEU have requested expansion of their EEC programs to Fort Nelson (Exhibit B-9, BCUC IR 1.192.3) and FortisBC Energy Whistler customers to comply with Commission Order G-138-10 which indicated concerns about the lack of DSM initiatives in the FEW service area. (Exhibit B-1, Appendix K-1, p. 17)

No Intervener made submissions on these requested approvals.

Commission Determination

The Commission Panel believes the requests of the FEU are reasonable and approves the request to expand EEC program eligibility to interruptible industrial, FortisBC Energy (Whistler) Inc. and FortisBC Energy Inc. Fort Nelson Service Area customers. The Panel is of the view that this approval will promote fair and reasonable access to EEC programs among customer classes.

8.6.2 Inclusion of Spillover Effects

Spillover effects are the energy savings attributable to customers undertaking an energy-saving activity who do not participate in a program. Free riders are those persons who would have taken the demand-side measure without an Incentive. Free riders therefore reduce energy savings by the estimated amount that would have been achieved without the DSM program. Both spillover and free ridership can be included in a utility's net to gross ratio, which is the ratio that adjusts the savings of DSM programs for cost effectiveness testing.

The FEU already provide information on free ridership in programs and are requesting Commission approval of the general concept of inclusion of spillover but have not included spillover estimates in their 2012-2013 EEC Plan. (Exhibit B-67, BCUC IR 3.6.3) If approved, the FEU would include an estimate of spillover effects for programs in future applications, where applicable.

The FEU agree that to the extent possible, the inclusion of spillover effects should be supported by comprehensive and convincing empirical evidence. (T9: 1476-7)

They submit that their current practice of including free riders but not spillover only adjusts DSM program benefits downwards but does not account for the positive effect of those participants who were influenced by the program but did not participate. (FEU Final Submission, p. 194)

Both BCSEA and CEC support the FEU's request to include spillover. (BCSEA Final Submission, p. 10; CEC Final Submission, p. 48)

Commission Determination

The Commission Panel agrees that the FEU's current practice of including free riders but not spillover adjusts DSM program savings downwards only and results in a one-sided adjustment to energy savings. However, the Panel believes it would not be appropriate to make a determination on the inclusion of spillover without a full assessment of the merits of including spillover based on a specific set of facts before the Commission. **Accordingly, the Commission Panel makes no determination on the inclusion of spillover in this RRA. The FEU may readdress this issue in future applications.**

8.6.3 EEC Framework

In the Application, the FEU have requested that the elements of their existing EEC Framework be retained. Those elements, which the FEU refers to as "accountability mechanisms" are:

- An overall funding envelope is approved by the Commission and EEC spending is not to exceed that level;
- The FEU will spend EEC funds only on approved Program Areas;
- The Companies have the ability to move funds among Program Areas and the FEU will report on those funding transfers in their EEC Annual Report;
- The FEU evaluate the EEC portfolio as an overall portfolio and monitor the portfolio TRC on a monthly basis;
- The FEU evaluate the Innovative Technologies Program Area as a separate segment having a benefit-cost ratio of 1.0 or greater;
- The Companies will hold EEC Stakeholder Group meetings and present updates on program progress and obtain stakeholder input on new programs and refinements to existing programs; and
- The FEU will file an EEC Annual Report with the Commission by the end of the first quarter of every year.

(Exhibit B-1, p. 775, and Exhibit B-1, Appendix K-1, pp. 4-5)

i) Funding Envelopes and Transfer of Funds Among Program Areas

The FEU have requested approval to: (a) have an overall funding envelope approved by the Commission; (b) only spend funds on approved Program Areas and (c) retain the right to move funds among approved Program Areas, reporting such transfers in their EEC Annual Report and to the EEC Stakeholder Group. (Exhibit B-1, Appendix K-1, p. 4)

The process for the FEU making funding transfers was examined during the Oral Hearing. The Companies stated that they file information on funding transfers in their EEC Annual Report and then discuss the Annual Report, at a high level, with their EEC Stakeholder Group. There is no suggestion that proposed funding transfers are discussed with the Group in advance. The FEU admit they have not contemplated what they would do in the situation where they make a funding transfer before presenting it to the Stakeholder Committee and when it is presented, the Stakeholder Group subsequently expresses opposition. (T9: 1472, 1474)

Commission Determination

The EEC Annual Report is a compliance filing. The FEU are currently not restricted from making funding transfers prior to review through a Stakeholder Committee meeting. Given this and the FEU's further lack of any process to deal with cases where the Stakeholders may oppose the transfer, the Commission has concerns with the lack of a third-party review of the Companies' funding transfers. This could lead to expenditures in specific programs growing to a level well in excess of what had been approved with no additional scrutiny. The Commission believes that to ensure proper oversight and accountability, it must balance the advantages of the FEU being able to move funds freely among approved Program Areas to meet the needs of existing or new programs against the need for the Commission to be assured that EEC expenditures continue to be in the public interest. **To achieve this balance, the Commission Panel has determined that the practice of transferring funds among Program Areas should be allowed to continue but with some limitations. Accordingly, the Commission approves the movement of funding to a maximum of 25 percent from one approved Program Area to another approved Program Area without prior approval of the Commission. In cases where a proposed transfer into an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval is required. Finally, the transfer of funds to new programs, not approved in this Application, or to Innovative Technologies (see below) will require prior Commission approval.**

ii) Portfolio Approach to Cost Effectiveness Screening

The FEU advocate the continued use of a portfolio approach for evaluating the cost effectiveness of

EEC programs. None of the Interveners objected to the continuation of this practice.

The FEU propose to monitor EEC programs on a monthly basis to ensure the overall EEC portfolio continues to meet the cost effectiveness test on an ongoing basis. (FEU Final Submission, pp. 184, 185)

Commission Determination

With the assurance that FEU will continue to monitor EEC programs on a monthly basis to ensure the EEC portfolio meets an MTRC of 1 or greater, the Commission approves the assessment of cost effectiveness on an overall portfolio basis, subject to further determinations regarding the Innovative Technologies Program Area discussed below.

iii) Innovative Technologies

In the Negotiated Settlement Agreement for 2009 and 2010, parties agreed that the Innovative Technologies Program Area is to be evaluated as a separate segment of the overall EEC portfolio and is to have a weighted average total resource cost (TRC) of 1.0 or greater.

The Innovative Technology Program Area consists of pilots and demonstration projects to develop technologies and programs to be market-ready. The FEU submit "[t]he point of innovative technology programs is to jump start fledgling market-ready technologies with substantial promise of greenhouse gas, energy-efficiency, and other benefits." (Exhibit B-9, BCUC IR 1.197.1)
In the current application the FEU is requesting approximately $3.0 million in EEC funding spread over two years.

Commission Determination

The Commission Panel views the Innovative Technologies Program Area as similar to a DSM

Research and Development department – it is the funding the FEU can use to test new technologies and run pilots. The Panel understands that the programs in this Program Area will not always be cost-effective. **Accordingly, the Commission Panel lifts the requirement for the Innovative Technologies Program Area to be evaluated as a separate segment of the EEC portfolio meeting TRC of 1 or greater as agreed to in the NSA for the 2010 and 2011 RRA. However, the Panel further determines that these programs need not meet the new MTRC test. The expenditures in this Innovative Technologies Program Area are subject to the portfolio level cost-effectiveness testing discussed above and are subject to the 33 percent cap for expenditures that do not pass the MTRC test as written in the DSM *Regulation* as discussed in Section 8.2. However, because these technologies may fall into the category of activities being dealt with by the AES Inquiry, the Panel directs that transfers of funds into or out of this program area are not to occur without prior Commission approval.**

iv) Stakeholder Group and EEC Annual Report

The FEU's EEC Stakeholder Committee does not have a Terms of Reference (TOR) although a draft had been tabled with the group shortly before the Oral Hearing. (Exhibit B-83, Undertaking 50) The TOR has not yet been approved by the Committee. As noted previously, the FEU concede that there is no current process for the stakeholder group to take a position on any issue and no process to deal with a situation where a member disagrees with a funding transfer. (T9: 1515, 1519) Further, the Companies concede that there are no formal processes for the EEC Stakeholder Group to critique and shape the FEU's programs. (T9: 1519, 1521-2)

The FEU submit that they solicit feedback from stakeholders and describe the group as "lively" and "would anticipate that if anyone had a major issue with program design or a particular program activity, they would raise it with us." (T9: 1519)

During the Oral Hearing the FEU EEC panel was asked whether their current approach gives them "carte blanche" in terms of the decision-making on the use of EEC funds. (T9: 1524) In response, Mr. Stout stated: "I don't think it does. And I say that because of the way the meetings are conducted, and the input taken back, and how we deal with it..." Ms. Smith further stated that "we're managing a portfolio of activity to a set of cost-effectiveness guidelines. We provide very extensive reporting on that activity." (T9: 1524)

The FEU currently provide the Commission with an annual report that in part,

- Evaluates EEC expenditures on an overall portfolio basis; and
- Reports on funding transfers between approved program areas.

Commission Determination

The Commission Panel's view is that if the Stakeholders are to have influence on the use of EEC funds, the group needs to have its feedback mechanisms and decision-making processes formalized in a Terms of Reference. The Commission Panel believes there is a continuing need for an active and effective EEC Stakeholder group, particularly in light of the expanding range of EEC activities being undertaken by FEU.

In order to increase the effectiveness of the EEC Stakeholder Group, the Commission Panel directs the FEU to develop a Terms of Reference in consultation with the Stakeholder Group. The Commission further directs the FEU to continue filing an Annual Report to the Commission but to add to this report a section detailing the EEC Stakeholder Group's views with attention to items such as funding transfers, new programs and any other material the Stakeholder Group deems appropriate and wishes to provide.

v) Programs that have Previously Been Rejected

In the TGI-TGVI 2009 Energy Efficiency and Conservation Programs Decision[24], the Commission rejected the NGV EEC Program and the Trade Relations Program. The NGV EEC Program was reviewed and dealt with in the EEC NGV Incentives Review Decision.

Prior to this Application, the FEU started their Efficiency Partners program which is substantially similar to the Trade Relations Program. The FEU are proposing to continue the Efficiency Partners program and submit that the 2009 EEC Decision[25] anticipated that the Trade Relations type of work would be undertaken in the Residential Program Area and that the FEU were transparent in reporting and consulting with stakeholders on these types of activities. (FEU Final Submission, p. 212)

The FEU did agree that it would be problematic to re-instate a Program Area that had been previously rejected. (T9: 1522-3)

While the Commission Panel sees merit in the Efficiency Partners program in this Application and approves it, the Commission recognizes that this program, under a different name was rejected previously. The Commission Panel considers it problematic for the FEU to re-instate a program that has been previously rejected or to start a program that is substantially similar to one that was previously rejected with no additional process. **Accordingly, the Commission Panel directs the FEU not to re-instate programs or Program Areas that have previously been rejected without approval of the Commission. When a program or Program Area has been rejected, the Commission directs the FEU to apply to the Commission for approval prior to spending EEC funds on that program or Program Area.**

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[24] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Energy Efficiency and Conservation Programs Application; Decision and Order G-36-09 dated April 16, 2009 (2009 EEC Decision)

[25] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Energy Efficiency and Conservation Programs Application; Decision and Order G-36-09 dated April 16, 2009 (2009 EEC Decision)

8.7 Other Identified Issues with EEC Portfolio

8.7.1 Evaluation, Measurement and Verification

During the Proceeding, the issue of the FEU's evaluation of their programs and the measurement and verification of their claimed energy savings was raised. The FEU submit that impact evaluations on three of their Residential and Commercial programs conducted between 2003-2010 have been completed. (Exhibit B-17, BCUC IR 2.97.1) In addition, they presented an evaluation schedule of their EEC programs for 2011 and 2012. (T9: 1477-8, Exhibit B-17, BCUC IR 2.118.1) This schedule includes more planned evaluations but the Companies state they have developed evaluation plans on a program by program basis. An overall evaluation plan has not been developed although the Companies have plans to hire a dedicated Evaluation, Measurement and Verification (EM&V) manager to develop "a formal structure and an evaluation framework" for all EEC programs. (T9: 1478, 1481) The FEU state that currently, all evaluations are conducted by third-party experts and the FEU submit that their evaluation process is in line with industry practice. (T9: 1481, FEU Final Submission, p. 209)

The FEU do not use the International Performance Measurement and Verification Protocol (IPMVP) although they have recently sent staff to the certification course. The FEU submit that there is no evidence that the IPMVP is widely used in the industry or that it is preferable to the methods used by the third party experts retained by the FEU.

The FEU argue that "they have employed a reasonable approach given the early stages of the EEC portfolio. The FEU are hiring an EM&V manager who will establish the appropriate EM&V framework." (FEU Final Submission, p. 210)

CEC agrees with the FEU and argue that "[t]he FEU's evaluation and measurement programs are evolving as expected and appropriate for the stage of development of EEC at which the FEU are now." (CEC Final Submission, p. 50)

Commission Decision

The Commission Panel sees benefit in the establishment of an EM&V Framework. **The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework.**

8.7.2 Integration with Other Utilities

BCSEA and its expert witness Mr. Plunkett raised the issue of integration of DSM programs among BC utilities. Mr. Plunkett's position is that "only one program should treat the customer to the extent that efficiency potential can be maximized and cost minimized with this approach" and that the FEU currently do a fair job of integrating gas and electric efficiency but that there is room for improvement. (Exhibit C4-5, BCUC IR 1. 11.1.1)

The FEU state that they do not have written protocols to prevent duplication between programs, but that department managers meet on a regular basis to compare programs and look for opportunities to cooperate. (Exhibit B-85, Undertaking 52, and T9: 1497)

The Companies agree that where programs are integrated it is important to avoid duplication of efforts to contact the same customer. They also agree that integrated programs may maximize use of ratepayer funds where customers' total energy (gas and electric) needs can be addressed. (T9: 1496, 1506)

The FEU currently run 11 programs in partnership with other BC utilities but do not currently have attribution rules between utilities for claiming energy savings. (Exhibit B-25, p. 3, Exhibit B-17, BCUC IR 2.119.1)

Commission Determination

The Commission agrees with Mr. Plunkett that integration of DSM programs from utilities and providing one point of customer contact for all DSM services, regardless of fuel type, is an efficient means of delivering DSM. The Commission encourages FEU to continue to provide integrated DSM programs so customers can easily access services to reduce all their energy needs, regardless of energy source.

The Commission Panel believes there is a need for the FEU to develop attribution rules and communication or other protocols and agreements necessary to avoid duplication of programming and to work towards creating streamlined processes for customers wishing to access DSM for all energy use. We also believe there is a need for the FEU to develop attribution rules with other utilities for integrated programs. **Therefore, the Commission Panel directs the FEU to develop attribution rules for all integrated programs which prevent the double counting of savings.**

8.7.3 PSECA Program and Overlap with AES Inquiry

In 2010 and 2011, the FEU participated in the Public Sector Energy Conservation Agreement (PSECA) program with BC Hydro and SolarBC. The PSECA Initiative was operated by the provincial Climate Action Secretariat (CAS). Under the PSECA Initiative, the CAS reviewed and approved applications for incentive funding for public sector organizations to reduce energy consumption and GHG emissions. The CAS then forwarded applications to the FEU who independently reviewed their eligibility for EEC incentive funding. (Exhibit B-1, Appendix K-4, pp. 74-77) The CAS has not committed further funding to the PSECA Initiative so FEU's PSECA program has been discontinued for 2012-2013. The FEU ran their PSECA program under the Commercial Program Area.

In 2011, the FEU project to spend $324,430 on the PSECA program for three school districts (SD): SD 72 Campbell River; SD 71 Comox Valley; SD 37 Delta. High efficiency boilers, heat pump chillers, and high efficiency water heaters were the measures eligible for incentives. Approximately $116 thousand in incentive payment was committed to Delta SD, a project where FEI owns the high efficiency boilers for which the incentives are committed. (Exhibit B-89, Undertaking No. 56)

The FEU advises that under the PSECA program, customers must submit an energy study to the FEU for verification by a third party professional and must install the measure before receiving an incentive. (FEU Final Submission, p. 210-211)

In their Final Submissions, both Corix and ESAC raise the issue of EEC administration.

ESAC requests the Commission make no final determination on the application of EEC funds to TES projects in light of the concurrent AES Inquiry but requests the Commission require FEU to immediately disclose any AES projects in which FEU may have involvement as an owner, operator or partner. (ESAC Final Submission, p. 9)

Corix submits the following: "the FEU have proposed EEC programs that can be accessed by TES projects, and in one case <u>create</u> a market for TES projects. If the FEU include EEC incentives as part of the package marketed to potential customers, or are <u>perceived</u> to do so, the FEU have a competitive advantage relative to other TES service providers." (Corix Final Submission, p. 16)

Corix has requested that the Commission make any decision related to FEU's TES business interim until determinations are made in the AES Inquiry, and also asks that the Commission implement third party administration of TES-related EEC programs. (Corix Final Submission, p. 3)

BCOAPO also submits that any approval of EEC activities that may be impacted by the AES Inquiry should be interim and subject to the outcome of the Inquiry. (BCOAPO Final Submission, p. 33)

A significant line of questioning by both Corix and ESAC in the Oral hearing was the communication that occurs between the EEC group and the TES group within the FEU. In their testimony and Final Submission, the FEU asserted that there was no communication between the Thermal Energy

Service group and the EEC group within FEU. (T8: 1345-6; FEU Final Submission, pp. 210-211) However, on January 6, 2012, after the close of the evidentiary record, the FEU provided a correction to their evidence which was contrary to their testimony. They now confirm that EEC group staff have discussed the Delta SD project with the Companies' Thermal Energy Service staff members. The purpose of those discussions was to review the requirements of the PSECA energy study, to clarify project costs, and to review and confirm the EEC incentive amounts. The FEU further emphasized that the EEC group communicated with the applicable engineers or consultants in their review of all PSECA applications. (Exhibit B-94, p. 2)

In response to this correction, ESAC made the following submission:

> "ESAC's contention in this process and in the AES Inquiry and the DSD CPCN Application is that, because of the inherent conflicts that exist when the regulated utility acts as trustee of EEC funds and at the same time has a separate vested business interest in developing a non-regulated business, extraordinary oversight is required. To the extent there was any doubt about the need for such oversight, we submit that the FEU has proved our case." (Exhibit C5-7, p. 4)

The FEU reply that the communications involved do not suggest the EEC incentive was unfairly administered and that the Delta SD PSECA application passed the CAS' screening and a third party review of the energy study. (FEU Reply Submission, pp. 58-59)

Commission Determination

The Commission Panel believes that EEC incentive funding for TES projects is more appropriately dealt with in the concurrent FEU AES Inquiry proceeding save for the issue of the PSECA funding that has been committed in 2011. The PSECA program is no longer running. Therefore, the issues the Commission may have with EEC funding through this program looking ahead are moot at this point. However, the principles at play in the provision of some of the funding under the PSECA program are at issue with the EEC funding to the Delta School Board, where the FEU own the installed high efficiency boilers and also provided the EEC incentives to the customer.

The evidence of this proceeding is on the record in the AES Inquiry. The Commission Panel believes that the issues which were raised by Corix and ESAC and any request for third party administration of EEC funding is more appropriately dealt with in that proceeding.

Accordingly, the Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry.

8.7.4 Impact of 2012/2013 EEC Expenditures on Future Rates

Of concern to the Commission Panel is the potential for the FEU's deferral accounts to grow significantly over the next period of time and have a magnified impact on future rates as the EEC program expands and expenditures continue.

The FEU have been clear in stating that there is no proposal in this RRA for 2012 and 2013 EEC funding amounts to continue in perpetuity. The FEU also state that the EEC program is subject to regular review and the Companies may well seek changes in the funding envelope in future revenue requirements or long term resource plan applications. Such changes will be made based on the success of programs and the achievement of EEC targets. The FEU also point out that the regular review and reporting of deferral account balances will occur through the rate setting and annual reporting processes. (Exhibit B-9, BCUC IR 1.6.1, Exhibit B-17, BCUC IR 2.93.3)

The Commission Panel notes there were two BCUC IRs requesting tables showing the build-up in balances for the FEU EEC Rate Base and EEC Non-Rate Base Deferral Accounts. (Exhibit B-17, BCUC IR 2.93.1, BCUC IR 2.93.3) These showed that the deferral account build-up would be in the hundreds of millions of dollars if current levels of spending were to be carried forward from 2012 to 2023. The Panel acknowledges that the information in the tables included in FEU's responses is out of date as the current proposal for EEC funding has been reduced. However, the information can at least be considered directionally correct and indicates there will be very large deferral account balances if current spending levels continue and the proposed method of amortizing these amounts is maintained. While no specific proposals have been put forward with respect to future expenditures, the Commission Panel believes it would not be unreasonable to assume that current robust expenditure requests will continue for some time. Therefore, while it may be premature to make a determination based on an assumption that the current rate of expenditure will continue, it would not be prudent to ignore the potential for growth in EEC deferral account balances. The fact remains that regardless of future expenditure levels, the amounts in the deferral accounts will likely be amortized over time and charged to ratepayers.

Both the CEC and BCOAPO have raised the issue of amortization and similarly argue that amortization periods should be tied to the useful life of the demand-side measure. (CEC Final Submission, p. 49; BCOAPO Final Submission, p. 35) The FEU submit that this approach would raise its own set of issues. Firstly, this proposal would result in varying amortization periods and, in some cases, no amortization period at all. In addition, the treatment of portfolio-wide costs would be a challenge. The Companies further submit that from the perspective of ease of administration and efficiency, a single amortization period for all programs is best and a 20-year amortization period would be most appropriate. (FEU Reply Submission, p. 52)

Commission Determination

The Commission Panel believes the appropriate time to consider these expenditures and their resultant impact on ratepayers is in the near term. However, due to the fact that many of the programs are in the early development stage or have yet to be implemented, we believe a final resolution of this matter can wait. **Accordingly, the Commission Panel, in the interests of providing a foundation upon which to examine the issue, directs FEU to provide a report detailing the rate impacts of four differing scenarios based on expensing EEC expenditures, and on amortizing them over a 5, 10 and 20-year period. This report is to be included with the next**

the next EEC expenditure application and each of these scenarios should incorporate the following:

- **An estimate of EEC program expenses for each year up to and including 2013;**
- **All EEC funds estimated to be spent by the end of 2013 and EEC forecast expenses for 2014 and beyond;**
- **Rate impacts for a 20 year period beginning in 2014; and**
- **Estimates of inflation for EEC Expenditures.**

8.7.5 EEC Expenditures and Rates – Alternative Models

BCOAPO comments on what it refers to as the existence of a "structural tension" for a gas utility in pursuing DSM measures. In the BCOAPO's view, there is an incentive for the utility to avoid pursuing DSM measures because its business model is dependent upon increasing gas sales to increase growth and the pursuit of DSM measures reduces gas sales. To offset this, BCOAPO notes that the Utilities have been allowed to earn a return on money which has been spent on DSM measures. The BCOAPO states that this creates a "perverse incentive" where it is in the interests of the utility to spend large amounts on ineffective DSM measures. This will allow the utility to earn the return on DSM expenditures without a significant reduction in sales. (BCOAPO Final Submission, p. 36)

The FEU submit that their EEC Annual Reports have extensively reviewed past EEC programs and the overall portfolio has been cost-effective. The position of the FEU is that this cost-effectiveness demonstrates that effective DSM is being undertaken. (FEU Reply, p. 51)

Commission Panel Discussion

In the view of the Panel, the issue is how to get the most value for the dollars being expended on

DSM programs. Within the regulatory world there are a variety of methodologies for handling DSM and related expenditures. To this point this jurisdiction has not undertaken a comprehensive review of what is in place elsewhere and the effectiveness of other models. Therefore, it is not known whether there are alternative models which could potentially result in British Columbia ratepayers getting more value for the dollars expended and yet still incent the utility to pursue DSM while being treated fairly as prescribed by the *UCA.* Areas which may be considered for examination include but are not limited to the following:

- What other options exist for the treatment of DSM expenditures and how is the cost of programs charged back to ratepayers?
- How do other jurisdictions avoid the structural tension issue and align the business objectives of the utility with the attainment of maximum DSM benefits for the ratepayer? What options exist to introduce incentives to assist in creating this alignment?
- What options exist in other jurisdictions to more effectively manage an integration of utilities' DSM initiatives and spending?

With increased emphasis on DSM programs and increasing levels of spending, the answers to these questions become increasingly important. The Commission Panel believes that it is appropriate that these questions be explored in a separate review process.

9.0 DISSENT OF COMMISSSIONER RHODES

I have read the draft Decision of my co-Panel members on the issue of FEI's expenditure on the Olympic Cauldron and, with respect, find myself unable to agree with their conclusion on that issue for the reasons which follow.

In my opinion, the Commission must be cautious in its consideration of non-essential, discretionary expenditures put forward by a public utility operating as a regulated monopoly in areas such as advertising, promotion, charitable donations and corporate development, as part of the public utility's "cost of service."

As noted in the Decision of the Panel Majority, FEI paid $3.21 million to fund the Olympic Cauldron in 2009. FEI has placed the "asset" into rate base as "Tools and Equipment" and now seeks to recover its remaining book value ($2.889 million) plus FEI's allowed rate of return from ratepayers over its estimated remaining useful life of 18 years.

The FEU take the position that the Cauldron benefits the Utilities' customers, hence they should bear 100 percent of its costs. They argue that the intrinsic value associated with "good corporate citizenship" will facilitate their work on utility infrastructure in the communities they serve. (FEU Argument, p. 161, Exhibit B-9-1, Attachment 5.2) The FEU state:

> "While the shareholder earns a return on capital it has invested in the cauldron (as it does with any invested capital in the utility), the reputational impacts associated with good corporate citizenship flow to customers of the operating utilities. They will continue to flow to customers over the life of this legacy investment." (FEU Argument, p. 162)

In my view, the value of "good corporate citizenship" is for the most part a benefit to the shareholder of a company, as opposed to its customers, and should be recognized as such. This reasoning is supported by the "Fortis Group of Companies of BC Communications & Public Affairs Plan for 2010/2011" (Communications Plan). (Exhibit B-17, Attachment 29.1) The

Communications Plan documents the renaming of Terasen Gas to identify the gas utility as one of the Fortis companies under combined leadership as a “significant opportunity to strengthen the brand.” Business priorities are noted as including:

- The integration of Terasen and FortisBC
- Renaming the companies with a common name
- Securing the base business (natural gas and electric)
- Integrating new products such as biogas and natural gas for transportation, and
- Growth – organic, energy infrastructure (capital projects) and acquisition.

An ongoing corporate focus on, among other things, community involvement, operational excellence and corporate social responsibility is viewed as helping to “differentiate the organization and provide a competitive advantage against other energy providers.” (Communications Plan – Executive Summary, p. 5)

The key brand message to be communicated is that “FortisBC is leading British Columbia into a sustainable energy future.” (Communications Plan – Executive Summary, p. 6)

In terms of promoting this brand, the Communications Plan notes:

> “It is important that the public is aware of all of our community efforts to ensure this part of the business is contributing to the leadership positioning in creating a sustainable future for all British Columbians. All communications within the communities, on the website, in social media, and in the annual report should focus on the direct benefit to the community versus the company’s contribution in order to reflect the appropriate tone.” (Communications Plan, p. 55)

In my opinion, the branding benefits discussed above flow solely to the Companies. I am of the further view that branding activity is far more important to the FEU’s broadening of its focus into new businesses, than to its mature monopoly gas distribution business, the customers of which are being asked to foot the bill.

The FEU witnesses were also unable to draw a one-for-one parallel between the funding of the Cauldron and improved community acceptance of the FEU's operations. Mr. Thomson testified as to his view that "it's a necessary part of ... doing business generally to make community investments and support activities around the province. Like all businesses do." (T3: 454-455)

Mr. Stout testified that in his experience, most organizations, large and small, make investments in the community to facilitate business. He noted that mining companies, independent power companies, oil and gas production companies and infrastructure companies that disturb the environment all invest in the community "as part of their social license to operate." (T5: 864) He also agreed that sponsorship costs provide some brand recognition/promotion but differentiated Fortis from brands such as Coca Cola or Nike. (T5: 865)

In my view, there is no doubt that many organizations provide community investment dollars either as part of their "social license to operate" or for promotion of their brands. However, in my further view, a distinction must be drawn between situations where corporate donations are made as part of doing business with no guarantee of dollar for dollar reimbursement, (let alone dollar for dollar reimbursement coupled with a return), or where donations are made to further a competitive brand as part of the competitive process, and the situation of a monopoly service provider making an expenditure and claiming full reimbursement.

In my opinion, the value of the community investment or corporate donation lies in the fact that it is a true donation from the corporate sponsor, albeit with a hope of recovery through increased sales, for example, as opposed to simply the footing of a bill for an expenditure in the first instance, with the expectation of full recovery from others (i.e. ratepayers), who may not even be aware that this is part of the "essential service" they pay to receive from their monopoly provider.

In terms of corporate or shareholder benefits as opposed to customer benefits, I further note that, as part of its "Olympic commitment," Terasen received certain rights to purchase what were very scarce tickets to Olympic events, including the Opening and Closing ceremonies. Although none of the tickets were purchased with ratepayer monies, this does not detract from the fact that Terasen, as opposed to its customers, did receive a real and direct benefit from its Olympic sponsorship. (Exhibit B-9-1, Attachment 5.2)

The FEU further argue that the Cauldron is a “used and useful” rate base asset. I agree with the BCOAPO and the Panel Majority that the Cauldron is downstream of the gas meter and is not relevant, as in used or useful, to the monopoly natural gas distribution business. In my opinion, regardless of the meaning of the term “used and useful” as it applies in regulation, the Cauldron in this case, as a downstream consumer of natural gas from time to time for ceremonial purposes, does not meet the test.

In consideration of all of the above, I would disallow the expenditure on the Cauldron in its entirety. In my view, to the extent that the shareholder in fact provides the Cauldron as community service (as is suggested on the plaque at the Cauldron), it will then actually be entitled to any goodwill that may have been generated from the donation.

DATED at the City of Vancouver, in the Province of British Columbia, this 12th day of April 2012.

Original signed by:

____

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

____

N.E. MACMURCHY
COMMISSIONER

DISSENT

I have read the draft Decision of my co-Panel members on the issue of FEI's expenditure on the Olympic Cauldron and, with respect, find myself unable to agree with their conclusion on that issue for the reasons stated in Section 9 of this Decision.

Original signed by:

____

A.A. RHODES
COMMISSIONER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-44-12

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

Application by the FortisBC Energy Utilities
(comprising 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: D.A. Cote, Panel Chair/Commissioner
A.A. Rhodes, Commissioner (dissenting in part) April 12, 2012
N.E. MacMurchy, Commissioner

O R D E R

WHEREAS:

A. On May 4, 2011, the FortisBC Energy Utilities (FEU or the Companies) filed an Application (Exhibit B-1) for the Revenue Requirements of 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 natural gas delivery 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 (Application);

B. FEI seeks, among other things, approval of a permanent natural gas delivery rate increase of 5.59 percent effective January 1, 2012, and a further 6.29 percent permanent increase effective January 1, 2013, pursuant to sections 59 to 61 of the Act;

C. FEI also seeks approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes for 2012, and approval of its cost allocation to Thermal Energy Services (previously referred to as Alternative Energy Services) for 2012 and 2013 as set out in the Application;

D. Fort Nelson seeks, among other things, no change to delivery rates for January 1, 2012, and approval of a 1.32 percent delivery rate increase effective January 1, 2013, pursuant to sections 59 to 61 of the Act;

…/2

E. Fort Nelson also seeks approval of the RSAM rider for applicable rate classes for 2012 as set out in the Application;

F. FEW seeks, among other things, approval of a permanent natural gas delivery rate increase of 5.02 percent effective January 1, 2012 and a further 6.54 percent permanent increase effective January 1, 2013, pursuant to sections 59 to 61 of the Act;

G. FEW also seeks approval of the RSAM rider for applicable rate classes for 2012 as set out in the Application;

H. FEVI seeks, among other things, approval 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, 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). 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;

I. FEVI also seeks approval of its schedule of demand and commodity charges, forecast gross operation and maintenance expenditures and its forecast cost of service, forecast capital expenditures, and forecast revenue pursuant to section 2.10 of the Special Direction;

J. The FEU seek, among other things, approvals relating to:

- Cost allocations for shared services between the Companies;
- The discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts;
- Changes to depreciation rates; and
- Proposed Energy Efficiency and Conservation (EEC) expenditures under section 44.2 of the Act;

K. On May 6, 2011, the Commission issued Order G-81-11 establishing a Regulatory Timetable for the review of the Application and setting dates for a Workshop and a Procedural Conference;

L. By Letters L-42-11 and L-45-11 dated May 24 and 26, 2011 respectively, the Commission amended the Regulatory Timetable;

M. The Workshop took place on May 18, 2011, and the Procedural Conference took place on July 7, 2011;

N. On July 19, 2011, the FEU filed an Evidentiary Update (Exhibit B-11) and on September 12, 2011, the FEU filed a second Evidentiary Update (Exhibit B-21);

O. By Order G-129-11 dated July 20, 2011, the Commission, among other things, ordered that an Oral Public Hearing to review the Application take place commencing on October 3, 2011, rejected the FEU request for interim rates and asked the FEU to resubmit their request for interim rates by October 1, 2011;

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P. On September 26, 2011, the FEU resubmitted their application for interim rates (Exhibit B-24);

Q. The Oral Public Hearing took place between October 3 and October 11, 2011, and between November 14 and 15, 2011;

R. At the Oral Public Hearing, the FEU filed revised financial schedules for FEVI (Exhibit B-52) and Fort Nelson (Exhibit B-66);

S. By Order G-177-11 dated October 20, 2011, the Commission approved interim rates, as requested, for the FEU effective January 1, 2012;

T. On December 2, 2011, the FEU filed their Final Submission;

U. On December 16, 2011, the FEU filed their submission on the impact of Ministerial Order No. M 335 which was issued on December 8, 2011, and amended the *Demand-Side Measures Regulation*, British Columbia Regulation 326/2008;

V. Between December 23, 2011, and January 6, 2012, the Interveners filed their Final Submissions;

W. By letter dated January 6, 2012, the FEU advised the Commission of a correction to the transcript;

X. By Order G-5-12 dated January 17, 2012, the Commission allowed the correction to the transcript and also allowed two Interveners to file further submissions on or before January 20, 2012. The two Interveners filed their submissions on that date;

Y. The FEU filed their Reply Submission on January 20, 2012; and

Z. The Commission has considered the Application, the evidence and the submissions all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. For FEI, pursuant to sections 59 to 61 of the Act:
    a. The requested permanent delivery rates for all non-bypass customers effective January 1, 2012, and January 1, 2013, representing an increase of 5.59 percent for 2012 and an additional 6.29 percent for 2013 are not approved as filed. Permanent delivery rate increases for all non-bypass customers effective January 1, 2012, and January 1, 2013, as recalculated by updating the financial schedules using the opening 2012 balance of net plant-in-service and rate base deferral accounts, updating the forecast final cost of the Fraser River Crossing Project reflecting the settlement amount that will be included in the final project report, and as modified by the directives in the Decision are approved.

b. The 2012 RSAM rider is approved. The 2013 RSAM rider is to be adjusted with the FEI Fourth Quarter 2012 Gas Cost filing.

c. The proposed 2012 and 2013 FEI overhead cost allocation to Thermal Energy Services (formerly Alternative Energy Services) is denied. The Commission directs FEI to allocate $750,000 for Thermal Energy Services in each year of the test period as set out in the Decision.

2. For FEVI, subject to recalculation by updating the financial schedules using the opening 2012 balance of net plant-in-service and rate base deferral accounts and updating the 2012 and 2013 forecast cost of gas, based on the five-day average forward prices for natural gas, consistent with the forecast natural gas prices utilized in the FEVI 2012 First Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account (the FEVI First Quarter Gas Cost Report):

   a. Permanent rates for 2012 and for 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 are approved as filed, pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction.

   b. FEVI's forecast Cost of Service for 2012 and 2013 as modified by the directives contained in the Decision is approved pursuant to section 2.10(a)(i) of the Special Direction.

   c. FEVI's forecast capital expenditures for 2012 and 2013 as modified by the directives contained in the Decision are approved pursuant to section 2.10(a)(i) of the Special Direction.

   d. FEVI's forecast revenue for 2012 and 2013, based on its proposed rates as modified by the directives contained in the Decision, is approved pursuant to section 2.10(a)(ii) of the Special Direction.

   e. The 2012 and 2013 cost of natural gas applied for, as updated based on the five-day average forward price for natural gas, consistent with the forecast natural gas prices utilized in the FEVI First Quarter Gas Cost Report, is approved pursuant to sections 59 to 61 of the Act.

   f. The difference between the net revenues received and the actual cost of service as modified by the directives in the Decision, excluding O&M variances from forecast, to be allocated to the RSDA for 2012 and 2013, is approved pursuant to sections 59 to 61 of the Act.

3. For FEW the requested permanent delivery rates for all customers effective January 1, 2012, and January 1, 2013, representing an increase of 5.02 percent for 2012 and an additional 6.54 percent for 2013 are not approved as filed. Permanent delivery rate increases for all customers effective January 1, 2012, and January 1, 2013, as recalculated by updating the financial schedules using the opening 2012 balance of net plant-in-service and rate base deferral accounts and as modified by the directives in the Decision are approved pursuant to sections 59 to 61 of the Act.

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4. For FEW, the 2012 RSAM rider is approved pursuant to sections 59 to 61 of the Act. The 2013 RSAM rider is to be adjusted with the FEW Fourth Quarter 2012 Gas Cost filing.

5. For Fort Nelson, subject to subject to recalculation by updating of the financial schedules using the opening 2012 balance of net plant-in-service and rate base deferral accounts and as modified by the directives in the Decision, permanent delivery rates for all customers effective January 1, 2012, representing no change for 2012 are approved pursuant to sections 59 to 61 of the Act.

6. For Fort Nelson, the requested permanent delivery rates effective January 1, 2013, representing an increase of 1.32 percent for 2013, are not approved as filed. Permanent delivery rate increases for all customers effective January 1, 2013, as recalculated by updating the financial schedules using the opening 2012 balance of net plant-in-service and rate base deferral accounts and as modified by the directives in the Decision are approved pursuant to sections 59 to 61 of the Act.

7. For Fort Nelson, the 2012 RSAM rider is approved pursuant to sections 59 to 61 of the Act. The 2013 RSAM rider will be adjusted with the Fort Nelson Fourth Quarter 2012 Gas Cost filing.

8. Pursuant to sections 59 to 61 of the Act, the following approvals are granted for FEI, FEVI, FEW and Fort Nelson to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012, as modified by the directives in the Decision:

   a. 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.

   b. The allocation of costs for shared services between FEI and FEVI.

   c. The allocation of costs for shared services between FEI and FEW.

   d. The consolidated Core Market Administration Expense (for FEI, FEVI and FEW), and allocation percentages.

9. FEI is directed to remove the cost of the Cauldron from FEI's rate base. The FEU is directed to include one half or $1.4445 million in costs for the Cauldron in its 2012 operating and maintenance expenses.

10. The FEU are directed to place the $401,092 cost of the West Coast Road extension and all related operating, maintenance and depreciation costs in a non-rate base deferral account bearing interest at FEU's long-term rate until the first customer connects to the main and consumes gas.

11. The FEU are directed to remove the mobile refueling unit from the Companies' assets, and all associated costs of the mobile refueling unit shall be removed from the FEU's revenue requirements in 2012 and 2013.

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12. 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 is approved subject to the following:

    a. The creation of an EEC non-rate base deferral account, attracting Allowance for Funds Used During Construction (AFUDC), to capture the additional EEC costs as incurred on an actual spend basis to a maximum of the total approved EEC expenditures less $15 million in 2012 and 2013 is approved without any determination on the amortization rate and recovery of this account at this time.

    b. The request to expand the compressed natural gas (CNG) and liquefied natural gas (LNG) Service Recoveries Deferral Account for the 2012 and 2013 forecast period is denied.

    c. The creation of the natural gas vehicle (NGV) Incentives deferral account is approved on the basis that this account attracts no return.

13. The applied for changes to the accounting policies to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012, as modified by the Decision, are approved.

14. With respect to EEC expenditures:

    a. Pursuant to section 44.2(a) of the Act, the Commission does not accept the EEC expenditure schedules for the FEU's EEC portfolio. The Commission accepts the EEC expenditure schedule up to a maximum of $36.304 million as calculated based on the directives in the Decision.

    b. The request to expand EEC program eligibility to interruptible industrial, FEW and Fort Nelson customers is approved.

    c. The requested treatment of EEC costs in accordance with the EEC deferral accounts as modified by the Decision is approved pursuant to sections 59 to 61 of the Act.

    d. The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry.

    e. The Commission directs the FEU to continue to file an EEC Annual Report pursuant to section 43 of the Act.

15. The FEU are to calculate 2012 and 2013 rates and file revised financial schedules including updated financial schedules with the opening balance of net plant-in-service and rate base deferral accounts, an update to the forecast final cost of the Fraser River Crossing Project reflecting the settlement amount that will be included in the Final Project report, FEVI's cost of natural gas updated based on the five-day average forward price for natural gas, consistent with the forecast natural gas prices utilized in the FEVI First Quarter Gas Cost Report, and in accordance with the directives in the Decision, by May 1, 2012.

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16. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. The FEU are to provide all customers, by way of an information notice and media publication, with a notice of the change in rates.

17. If the 2012 permanent rates are less than the interim rates, the FEU are to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which the FEU conduct their business. If the 2012 permanent rates exceed the interim rates, the interim rates from January 1, 2012 to the date of this Order are confirmed as permanent.

18. The FEU will comply with all directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 12th day of April 2012.

BY ORDER

Original signed by:

D.A. Cote
Panel Chair/Commissioner

COMMISSION PANEL'S DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	The Commission Panel approves the residential demand forecast as filed for use in calculating the FEU's 2012 and 2013 revenue requirements. The Commission Panel agrees with the BCOAPO that it would be of value for the FEU to file a financial analysis of the impact of variances in the forecast of customer additions on all rate classes when they file their next RRA and the FEU are directed to do so.	26-27
2.	The Commission Panel approves the FEU's Commercial Energy Demand forecast for the purpose of calculating their 2012 and 2013 revenue requirements. The Panel notes that the forecast follows a previously approved methodology and more importantly, has provided reasonable results. In addition, the Panel notes that any UPC variances are managed through the RSAM, which protects the interest of ratepayers. The Commission finds the methodology used to forecast industrial demand to be reasonable and approves it for use in calculating the FEU's revenue requirements in 2012 and 2013.	28
3.	The Commission Panel accepts the calculation of O&M labour and benefits increases as outlined in Table 5.3-2 of the Application.	30
4.	The Commission Panel has determined that ratepayer cost should not be mitigated for failed or delayed implementation of AES initiatives.	32
5.	The Companies are directed to file any existing retirement management plan with the Commission as soon as possible and no later than June 1, 2012. In the event no such plan has been developed, the Commission Panel directs the FEU to prepare a plan with a 5-year time horizon, by Department, detailing the specific actions they will need to take, what the costs are estimated to be and a timeline estimate. The FEU are directed to file this plan by no later than August 1, 2012.	33
6.	The Commission Panel finds that the evidence indicates the benefits achieved during the PBR period have eroded.	37

7.	The Commission Panel directs the FEU to reduce O&M expenditures for each of 2012 and 2013 by $4.0 million. In the view of the Panel, a $4 million reduction (1.53 percent) is very achievable from a total proposed $261.1 million in O&M expenses, especially given the past history of the PBR period. Where these cost reductions are applied is left to the discretion of the Companies. These reductions will be increased by any further reductions which are directed as a result of the review of new activities and initiatives at the departmental level. The Commission Panel further directs the FEU to file a Productivity Improvement Plan with their next revenue requirements application. The Productivity Improvement Plan may take the form of a proposal for PBR which places emphasis on both-short term activities as well as long term, sustainable improvements.	39
8.	The Commission Panel approves expenditures of $168 thousand for two of the three new Asset Compliance Manager positions in 2013 (two thirds of the $250 thousand requested for these positions).	43
9.	The Commission Panel does not accept that the need for the full number of requested employees has been established and has determined that it will only approve two rather than three additional Planners in each of 2012 and 2013. The Commission Panel directs FEI to reduce the O&M budgets by one FTE Planner position in 2012 and 2013 to reflect this. The Commission Panel approves all other applied for incremental expenses for Distribution and Asset Management.	45
10.	The Commission Panel accepts the need for the replacement of the right-of-way markers and is satisfied that FEU is handling the timing of the upgrade program in a reasonable manner.	47
11.	The Commission Panel notes the position the FEU have taken with respect to the further development of this business. There is no evidence of any further increase in LNG sales which are forecasted beyond the Vedder LNG refuelling station. Therefore, the Panel accepts a proportionate share of the $133,000 requested for 2012 and in 2013 the amount of $48,000, and rejects the $106,000 request for 2013 in its entirety. In addition, the Panel confirms that in keeping with the CNG/LNG Decision (Order G-128-11), FEU must ensure that any incremental O&M costs associated with LNG liquefaction are recovered under Rate Schedule 16. The Commission Panel approves the remainder of the incremental expenses requested for the Transmission group.	48
12.	The Commission Panel denies the two proposed additional business developers, one in 2012 and one in 2013 costing approximately $84 thousand in 2012 and $154 thousand in 2013, which represents the direct cost of the positions.	51

13.	The Commission Panel approves the Customer Service O&M budgets as proposed. However, the Panel expects the FEU to address the matter of leveraging the Customer Care function to maximize productivity opportunities in the next revenue requirements application. This should provide ample time for stabilization of the system and a better understanding of potential opportunities. Subject to the determinations made elsewhere in this Decision, the Commission Panel is satisfied with the FEU's forecast for the Customer Service Department's O&M budget.	52-53
14.	The Commission Panel approves the O&M budget for the Operational Engineering Department for the test period.	54
15.	Other than the LTRP and areas addressed elsewhere in this Decision, the Commission Panel approves the O&M budget for the ES&ER department for the test period as the Commission Panel supports the Companies initiatives to increase public safety education.	55
16.	The Commission Panel will only approve additional funding in the amount of $400 thousand in 2012 and $600 thousand in 2013 for resource planning of the $1.2 million requested in 2012 and $1.5 million in 2013.	59
17.	The Commission Panel accepts the requested increases in the Operations Support department for the test period.	60
18.	The Commission Panel approves the Human Resources budget increases as requested.	62
19.	The Panel approves the FEU IT O&M budget, subject to the directives contained in this Decision.	64
20.	The Commission Panel is not persuaded by the evidence that the FEU's growth-driven O&M IT costs are related to the services received by traditional gas customers given the flat growth rate in customer load. The FEU are directed to allocate this requested increase of $92 thousand in 2012 and $104 thousand in 2013 to the AES deferral account in addition to the Commission approved overhead allocation.	65
21.	The Commission Panel does not approve the FEU's requests for $89 thousand in 2012 and $129 thousand in 2012 to move certain IT services in-house.	66

22.	FEI is directed for future revenue requirements to determine potential alternatives for the delivery of the environmental training program and potentially integrate it with other training initiatives.	67
23.	The Commission Panel approves all incremental cost requests for the EH&S group. The Commission Panel has reviewed the budget for the Facilities department, and subject to adjustments made elsewhere in this Decision, approves the requested spending in the test period.	68
24.	The Commission Panel has reviewed the FEU's forecast O&M for Finance and Regulatory Affairs for the test period, as amended, and approves the amended forecast costs as consistent with Commission Order G-117-11.	69
25.	The Commission Panel directs the FEU to update both the Corporate and Shared Service Agreements for inclusion in their next revenue requirements application. Further, the Commission Panel directs the FEU to break activities of the FEU entities into two, distinct parts: • Those of traditional gas operations, and • Those of TES offerings so that costs attributable to each entity of the FEU can be clearly broken down by their TES component.	71
26.	The Commission Panel directs that all Community Involvement Spending will be allocated 50 percent to the ratepayer and 50 percent to the shareholder.	73
27.	The Commission Panel directs that the cost of the Cauldron be removed from FEI's rate base.	76
28.	The Commission Panel finds that the FEU's shareholder has received benefit from funding the Cauldron. The Commission Panel approves one half, or $1.4445 million in costs for the Cauldron in FEI's 2012 O&M expenses. The balance is to be absorbed by the shareholder.	77
29.	The Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application.	78

30.	The Commission Panel accepts Gannett Fleming's Depreciation Study and approves the changes in depreciation rates recommended by that study as it is satisfied that those rates best match the actual service lives of assets with the period of benefit to ratepayers at this time.	80
31.	The Commission Panel directs that a deferral account be established to capture the variances between forecast depreciation and actual depreciation in the test period as well as the directly attributable variance between forecast tax impacts and actual tax impacts for the test period only. The FEU are directed to report the annual additions to this deferral account by asset class in a report to be included with the Utilities' Annual Regulatory Report.	81
32.	The Commission Panel accepts the FEU's proposed application of the traditional method of providing negative salvage in rates during the test period.	83
33.	The Commission Panel directs the FEU to establish a rate base credit account to tabulate the total net negative salvage provisions less actual salvage costs. The Panel does not approve the presentation of the net negative salvage provision as a component of plant-in-service within the Utilities' assets.	84

34.	The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications. The FEU are directed to provide annual reports to the Commission, of total accumulations, by asset class, of the following: i) total salvage provision for the period, ii) total salvage expenditures, iii) a description of the total value of the asset rate base retired by asset class, iv) descriptions of the most common methods of retirement used during the period, v) the annual and cumulative to date (starting in 2012) actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired, and a comparison of how that rate compares to the rate recommended in the prior depreciation study, vi) a general description of any major trends or retirements that have occurred in the year (i.e. a specific type of pipe or type of meter that required a significant retirement), and vii) an update of trends, any alternative retirement methodologies not being used by the FEU and the future outlook of retirement procedures for each asset class including a description of how any changes in methodologies or available technologies could affect retirement costs.	85
35.	The Commission Panel directs the Utilities in the future to fully and transparently disclose the nature and amount of all assets or amounts included in their plant in service account that are being depreciated into rates but are not in use, or are not expected to be in use in the test periods, whether due to retirement or for other reasons.	87

36.	The Panel directs that the Asset Losses be recovered from ratepayers, as proposed, in current depreciation rates. While losses of this nature may be a part of group asset depreciation, the Commission Panel directs the Utility to disclose specific information in future filings with the Commission. The disclosures should include the following: 1) Future revenue requirements applications shall include details of actual asset losses, by asset class, for the past 10 years. They shall also include a forecast of losses, by asset class, for the remaining asset class, unadjusted for capital additions expected to occur outside the test period. As asset losses are expected under group depreciation, the Commission Panel believes that a projection of these losses should be readily determinable and should directly tie into depreciation forecasting methodology. When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates. 2) Future revenue requirements applications shall detail efforts made to minimize early asset retirements and to demonstrate how the utility intends to maximize the value of assets in use. As group depreciation methodology determines assets' useful lives on an average basis, the Commission Panel expects that at least some of the assets should be expected to last longer than their estimated useful lives. The Utilities shall describe the steps taken to determine which assets these might be and how the Utilities intend to identify, maintain and repair such assets. Furthermore, this process should incorporate capital asset maintenance plans to demonstrate how the value of assets in use is to be maximized such that assets are not just replaced, on a blanket basis, at the end of the assets' average service life.	88
37.	Given that no customers have attached to the West Coast Road extension since construction was complete on June 1, 2009, the Commission Panel determines that it is not "used and useful." Accordingly, the Panel directs FEU to place the $401,092 cost of the extension and all operating, maintenance and depreciation costs in an interest bearing non-rate base deferral account until the first customer connects to the main and consumes gas.	91
38.	The Commission Panel directs the FEU to provide a status update on the LTSP, systems developed and the nature of assets replaced in their next revenue requirements application.	93

39.	The Commission Panel approves the forecast 2012 and 2013 FEU growth capital expenditures for mains, services and meters. The Commission Panel approves the forecast 2012 and 2013 Biomethane expenditures of $3.1 million and $3.6 million, subject to the criteria and limitations set out in the Biomethane Decision and Commission Order G-9-12 in the AES Inquiry.	99
40.	The Commission Panel accepts the forecast of zero capital investments in NGV fuelling assets in 2012 and 2013. The Commission Panel accepts that these facility and equipment capital expenditures are necessary to support various components of the FEU's operations and therefore approves the FEU's requests for Facilities and Equipment Capital Expenditures.	100
41.	The Commission Panel approves the FEU's IT capital budget for 2012 and 2013.	101
42.	The Commission Panel directs the FEU in future RRAs to clearly identify either a shortcoming in current customer service levels or provide a fulsome budgeted O&M cost reduction, including the year of realization of expected savings, resulting from each significant IT Capital project in order to justify spending requests.	102
43.	The Commission Panel approves the inclusion of the second tanker in rate base. The Panel finds that the FEU have established the need of having one standby tanker. The Commission Panel accepts the proposed depreciation methodology for the new tanker for the purposes of setting rates in the test period, however, the Commission Panel directs the FEU to provide an estimate of the useful life of the new tanker which is related to hours of use in addition to the estimate already provided, taking into account the forecast use for transportation services to LNG customers.	103
44.	The Commission Panel finds that the mobile LNG refuelling unit is not an asset which should in any way be for the account of the natural gas distribution ratepayer and, to the extent that the FEU have included this asset in rate base, directs the FEU to remove the associated costs.	104

45.	The Commission Panel approves the creation of the Fort Nelson Revenue Surplus Account as requested by the Utilities. The Commission Panel approves the discontinuance of the Residential Commodity Unbundling Account, the Commercial Commodity Unbundling Account, and the IFRS transitional Account.	106
46.	The Commission Panel finds that the modifications to margin related deferral accounts are appropriate and in the interest of ratepayers and approves them as filed. The Commission Panel approves the continuation of existing margin related deferral accounts as applied for as they continue to reduce rate volatility.	107
47.	The FEU are directed to recalculate the mid-year balances in the Energy Efficiency and Conservation deferral account based on the Commission determinations with respect to this account in Section 8.0. The Commission Panel finds the NGV Conversion Grant Program deferral account as applied for is appropriate and is approved.	109
48.	The Commission Panel finds that establishment of an Emission Regulations Deferral Account is appropriate given the uncertainties surrounding the costs and revenues that could accrue to the FEU.	111
49.	The Commission Panel accepts the FEU proposal and approves the change for the Biomethane Variance Account from rate base to non rate base.	112
50.	The Commission Panel denies the request to expand the use of the CNG and LNG Service Recoveries Deferral Account for the 2012 and 2013 forecast period.	113
51.	The Commission Panel approves the creation of the NGV Incentives deferral account attracting no return. As a result of the circumstances outlined in the EEC NGV Incentive Review Decision, the Panel concludes that the FEU should not receive a return at this time on the funds. A final determination as to whether the deferral account should attract a return is left to the prudency review.	114
52.	The Commission Panel approves the creation of the Customer Service Variance Account as applied for with the amortization period to be determined in the next revenue requirements application of the FEU.	115

53.	The Commission Panel approves the continuation of non-controllable items deferral accounts as applied for. The Commission Panel approves the requested modifications to existing non-controllable deferral accounts.	116
54.	The Commission Panel approves the new deferral accounts for the 2012-2013 Revenue Requirements Application, AES Inquiry and Long Term Resource Plan application as applied for. The Commission Panel approves the continuation of other deferral accounts for BCUC application costs as applied for.	118
55.	These Other deferral accounts are consistent with past Commission decisions and are approved as applied for.	120
56.	The Commission Panel finds the proposed changes of the Other deferral accounts to be reasonable because the changes reflect a more accurate match of costs to their associated benefits. Therefore, the Commission Panel approves the changes as applied for.	121
57.	The Commission Panel finds the establishment of a deferral account for the Gas Records Project is reasonable and that a five year period is appropriate given the expected duration of the project.	122
58.	The three new US GAAP Deferral Accounts namely the US GAAP Transitional Account, US GAAP Pension and OPEB Funded Status Account and US GAAP Uncertain Tax Positions Deferral Accounts are approved as applied for. The new Muskwa River Crossing 2011 Deferral Account is approved as proposed.	123
59.	The Commission Panel finds the establishment of a deferral account as proposed for the BC One Call Project appropriate given potential uncertainties with costs and the timing of the project. The proposed allocation of costs is consistent with the cost allocation methodology applied to similar types of projects. The BC One Call Project Deferral Account is approved as proposed.	124
60.	The Commission Panel approves the creation of the Residual Delivery Rate Riders Deferral Account as requested. The Commission Panel finds that the existing residual deferral accounts continue to be appropriate and in the interest of ratepayers and approves them as filed.	125

61.	The Commission Panel sets the reconnect fee for regular hours at $90 and after hours at $115. These numbers, in the Panel's view, better reflect the cost of the service. The Panel also agrees that the FEU may wish to target customers who have trouble paying their bills for possible EEC or other funding such that a portion of the disconnections historically experienced may be avoided in the future.	129
62.	In the Commission Panel's view, the allocation of overhead and sales and marketing costs to Thermal Energy Services is insufficient and therefore the proposed $500 thousand overhead allocation for TES is denied. The Panel finds that a more reasonable allocation of overhead and sales and marketing costs would be $750,000 for each year of the test period as opposed to the $500,000 now being allocated. This amount would be in addition to the direct sales and marketing costs of the TES group already identified and allocated to the appropriate deferral account by the Utilities. The FEU are directed to propose criteria which can be used to provide a better assessment of an appropriate overhead and sales and marketing cost allocation.	139
63.	The Commission Panel directs the FEU to begin investigating the cost of fully converting to the USoA and to work with Commission staff to develop a plan that will allow the FEU to fully adopt the USoA prior to filing their next RRA with the Commission. A proposed plan for conversion within the timelines presented should be discussed with Commission staff and filed with the Commission no more that 180 days from the date of this Decision. The filing should identify any cost deferral account mechanism needed to facilitate the changeover.	142
64.	The Commission Panel approves the proposed changes in the methodology for allocating SCP costs and revenues between the delivery margin and the MCRA, and the allocation of the Spectra Energy Kingsvale T-South charges related to the NWN capacity. The Panel also approves the continuation of the debiting of the MCRA and the crediting of the delivery margin revenue in the amount of $3.6 million per year for 2012 and 2013.	143
65.	The Commission Panel directs FEVI to continue to report FEVI's forecast gas costs and GCVA balances on a quarterly basis and approves discontinuing quarterly reporting of the customer additions and the comparison to the competitive market.	144

66.	To assist in understanding how best to amortize EEC expenditures and over what term, the FEU are directed to provide a report detailing the rate impact of a number of amortization scenarios which will be helpful in determining a long term solution. For the 2012/2013 test period, the Commission Panel is satisfied that the proposed 10-year amortization period for the rate base deferral account is reasonable as is the FEU's proposal to allocate costs based upon the average number of customers served by each Company. Accordingly, the Commission Panel approves the following: 1. EEC rate base additions of $15 million in both 2012 and 2013 to be included on a net-of-tax basis and amortized in rates over a 10-year period. 2. The allocation of the 2012 and 2013 EEC rate base deferral account non-incentive additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. 3. The allocation of 2012 and 2013 EEC incentive costs on an as incurred basis. 4. The creation of an EEC Non-Rate Base deferral account, attracting AFUDC, to capture the additional EEC costs as incurred on an actual spend basis to a maximum of the total approved EEC expenditures less $15 million in 2012 and 2013. No determination on amortization rates will be made at this time.	151
67.	The Commission Panel directs the FEU to take greater advantage of opportunities to collaborate with other utilities with respect to CEO campaigns and communications. In pursuing a more collaborative approach to these types of programs, we believe that there will be savings and available funds can be more effectively used. Accordingly, the Commission Panel approves a reduced amount totalling $2.9 million for both 2012 and 2013 for Existing CEO programs which are currently active.	160
68.	The Commission Panel approves the requested expenditures of $18.209 million in 2012 and $18.206 million in 2013 for Existing Program Areas (excepting CEO Programs) which are currently active.	163
69.	The Commission Panel approves 40 percent or $6.598 million of the requested expenditures for new programs in Existing Program Areas in 2012 and 80 percent or $13.098 million of requested expenditures for 2013.	165

70.	The Commission Panel rejects the expenditures proposed for the Solar Thermal Program Area and the Thermal Energy for Schools Program Area. The Commission Panel also rejects the expenditure of $10 million annually for the Furnace Scrap-it program in 2012 and 2013. However, the Commission Panel believes that the Furnace Scrap-it program has potential and approves expenditures of $2 million for each of 2012 and 2013 for the Furnace Scrap-it program. The Commission Panel directs the FEU to include the Furnace Scrap-it program under its Residential Program Area.	168
71.	The Commission Panel believes the requests of the FEU are reasonable and approves the request to expand EEC program eligibility to interruptible industrial, FortisBC Energy (Whistler) Inc. and FortisBC Energy Inc. Fort Nelson Service Area customers.	170
72.	The Commission Panel makes no determination on the inclusion of spillover in this RRA. The FEU may readdress this issue in future applications.	171
73.	The Commission approves the movement of funding to a maximum of 25 percent from one approved Program Area to another approved Program Area without prior approval of the Commission. In cases where a proposed transfer into an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval is required. Finally, the transfer of funds to new programs, not approved in this Application, or to Innovative Technologies (see below) will require prior Commission approval.	173
74.	The Commission approves the assessment of cost effectiveness on an overall portfolio basis, subject to further determinations regarding the Innovative Technologies Program Area discussed below.	174

75.	The Commission Panel lifts the requirement for the Innovative Technologies Program Area to be evaluated as a separate segment of the EEC portfolio meeting TRC of 1 or greater as agreed to in the NSA for the 2010 and 2011 RRA. However, the Panel further determines that these programs need not meet the new MTRC test. The expenditures in this Innovative Technologies Program Area are subject to the portfolio level cost-effectiveness testing discussed above and are subject to the 33 percent cap for expenditures that do not pass the MTRC test as written in the DSM *Regulation* as discussed in Section 8.2. However, because these technologies may fall into the category of activities being dealt with by the AES Inquiry, the Panel directs that transfers of funds into or out of this program area are not to occur without prior Commission approval.	175
76.	The Commission Panel directs the FEU to develop a Terms of Reference in consultation with the Stakeholder Group. The Commission further directs the FEU to continue filing an Annual Report to the Commission but to add to this report a section detailing the EEC Stakeholder Group's views with attention to items such as funding transfers, new programs and any other material the Stakeholder Group deems appropriate and wishes to provide.	176
77.	The Commission Panel directs the FEU not to re-instate programs or Program Areas that have previously been rejected without approval of the Commission. When a program or Program Area has been rejected, the Commission directs the FEU to apply to the Commission for approval prior to spending EEC funds on that program or Program Area.	177
78.	The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework.	179
79.	The Commission Panel directs the FEU to develop attribution rules for all integrated programs which prevent the double counting of savings.	180
80.	The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry.	183

81.	The Commission Panel, in the interests of providing a foundation upon which to examine the issue, directs FEU to provide a report detailing the rate impacts of four differing scenarios based on expensing EEC expenditures, and on amortizing them over a 5, 10 and 20-year period. This report is to be included with the next the next EEC expenditure application and each of these scenarios should incorporate the following: • An estimate of EEC program expenses for each year up to and including 2013; • All EEC funds estimated to be spent by the end of 2013 and EEC forecast expenses for 2014 and beyond; • Rate impacts for a 20 year period beginning in 2014; and • Estimates of inflation for EEC Expenditures.	184-185

REGULATORY PROCESS

The FortisBC Energy Utilities, consisting of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Whistler) Inc. and FortisBC Energy (Vancouver Island) Inc., filed their 2012-2013 Revenue Requirements and Natural Gas Rates Application on Mary 4, 2011, with the Commission.

By Order G-81-11, dated May 6, 2011, the Commission established an interim regulatory timetable including a procedural conference schedule for June 15, 2011. The date for the procedural conference was amended and moved to July 7, 2011 by Letter L-45-11.

By Order G-129-11 dated July 20, 2011, the Commission established an oral hearing process to review the 2012-2013 Revenue Requirements and Natural Gas Rates Application commencing October 3, 2011.

The Oral Public Hearing to review the Application commenced on October 3, 2011 through October 11, 2011. It was then adjourned until November 14, 2011 and was completed on November 15, 2011.

In addition to the Oral Public Hearing, the review process included two initial rounds of Information Requests, a Supplemental Information Request related to the application for approval of various LNG matters, an Information Request to the B.C. Sustainable Energy Association and the Sierra Club of British Columbia from the Commission and a third round of Information Requests related to the to the EEC plan filed by the FEU with their rebuttal evidence. Three rounds of Information Requests (including Information Requests related to the EEC plan filed by the FEU with their rebuttal evidence) were also received from the Interveners.

On October 20, 2011, the Commission issued Order G-177-11 granting the Companies interim approval of requested rates and Energy Efficiency and Conservation funding in the amount of $5 million in the test period.

The FortisBC Energy Utilities filed their Final Submission on December 2, 2011, which was followed by Final Submissions from the B.C. Sustainable Energy Association and Sierra Club of British Columbia, the Commercial Energy Consumers Association of British Columbia, the Large Industrial Users Group, and the Energy Services Association of Canada on December 23, 2011; Corix Utilities Inc. filed the Final Submission on January 3, 2012, and the British Columbia Old Age Pensioners' Organization on January 6, 2012. The FortisBC Energy Utilities filed their Reply Submission on January 25, 2012.

LIST OF REGISTERED INTERVENERS

C1-1	British Columbia Old Age Pensioners' Organization (BCOAPO)
C2-1	Commercial Energy Consumers Association of British Columbia (CEC)
C3-1	British Columbia Hydro and Power Authority (BC Hydro)
C4-1	B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA)
C5-1	Energy Services Association of Canada (ESAC)
C6-1	Corix Utilities Inc. (Corix)
C7-1	Clean Energy Fuels
C8-1	Large Industrial Users Group (LIUG)

LIST OF ACRONYMS

2009 ROE Proceeding	Return on Equity and Capital Structure Proceeding from 2009
2010 LTRP	2010 Long Term Resource Plan
AES	Alternative Energy Solutions
Application	2012 and 2013 Revenue Requirements Application
ARO	Asset Retirement Obligation
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization
BCSEA	B.C. Sustainable Energy Association and Sierra Club of British Columbia
CAS	Climate Action Secretariat
CBOC	Conference Board of Canada
CCA	Capital Cost Allowance
CCE	Customer Care
CCRA	Commodity Cost Reconciliation Account
CEA	*Clean Energy Act*
CEC	Commercial Energy Consumers Associations of BC
CEO	Conservation education and Outreach
CMHC	Canada Mortgage and Housing Corporation
CNG	Compressed Natural Gas
Commission, BCUC	British Columbia Utilities Commission
Corix	Corix Utilities Inc.
CPI	Consumer Price Index

CSA	Canadian Standards Association
DSD	Delta School District
EARSL	Expected Average Remaining Service Life
ECAP	Energy Conservation Assistance Program
EEC	Energy Efficiency and Conservation
EF	Efficiency Factor
EH&S	Environment Health and Safety
ES&ER	Energy Solutions and External Relations
ESAC	Energy Services Association of Canada
ESRD	Energy Supply and Resource Development
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
FEU, Companies, Utilities	FortisBC Energy Utilities
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FHI	FortisBC Holdings Inc.
Fort Nelson	FortisBC Energy Inc. Fort Nelson Service Area
GCVA	Gas Cost Variance Account
GHG	Greenhouse Gas
GT&C	General Terms and Conditions
HRIS	Human Resources Information System Roadmap
IR	Information Request
IT	Information Technology
LIUG	Large Industrial Users Group

LIST OF ACRONYMS

LNG	Liquid Natural Gas
LTRP	Long Term Resource Plan
LTSP	Long-Term Sustainment Plan
MCRA	Midstream Cost Reconciliation Account
MX	Main Extension
NGV	Natural Gas Vehicle
NSP	Negotiated Settlement Process
NWN	Northwest Natural
O&M	Operations and Maintenance
OSR	Operation Support Representative
PavCo	Pavilion Corporation
PBR	Performance Based Rates
PSECA	Public Sector Energy Conservation Agreement
RLCFRR	Renewable and Low Carbon Fuel Requirements Regulation
RMDM	Retail Markets Downstream of Meter
RSAM	Rate Stabilization Adjustment Mechanism
RSDA	Rate Stabilization Deferral Account
SCP	Southern Crossing Pipeline
SEC	Securities Exchange Commission
Terasen	Terasen Gas Inc.
Terasen Companies	Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas Whistler Inc.
TES	Thermal Energy Services

TOR	Terms of Reference
TRC	Total Resource Cost
UCA	*Utilities Commission Act*
UCT	Utility Cost Test
UPC	Use Per Customer
US GAAP	United States Generally Accepted Accounting Principles
USoA	Uniform System of Accounts

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Energy Utilities comprising of
FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area,
FortisBC Energy (Whistler) Inc., FortisBC Energy (Vancouver Island) Inc.
2012 and 2013 Revenue Requirements and Natural Gas Rates Application

EXHIBIT LIST

EXHIBIT NO.	DESCRIPTION
COMMISSION DOCUMENTS	
A-1	Letter dated May 5, 2011 – Appointment of Commission Panel
A-2	Letter dated May 6, 2011, and Order G-81-11 – Establishing an initial Regulatory Timetable
A-3	Letter L-42-11 dated May 24, 2011 – Amended Regulatory Agenda and Timetable
A-4	Letter L-45-11 dated May 26, 2011 – Amended Regulatory Agenda and Timetable
A-5	Letter dated June 2, 1011 – Information Request No. 1 to FortisBC Energy Utilities
A-6	Letter dated June 27, 2011 – Procedural Conference discussion items
A-7	Letter dated July 20, 2011 – Amended Regulatory Timetable and Reasons for Decision
A-8	Letter dated July 21, 2011 – Information Request No. 2 to FortisBC Energy Utilities
A-9	Letter dated August 26, 2011 – Supplemental Information Request
A-10	Letter dated September 1, 2011 – Request for comments
A-11	Letter dated September 2, 2011 – Information Request No. 1 to BCSEA
A-12	Letter dated September 14, 2011 – Order G-158-11 and Reasons for Decision
A-13	Letter dated September 20, 2011 – Matters of prudency clarification
A-14	Letter dated September 23, 2011 – Procedural Information
A-15	Letter dated September 29, 2011 – Further letter regarding Procedural Conference

EXHIBIT NO.	**DESCRIPTION**
A-16	Letter dated October 17, 2011 – Commission Information Request No. 3 regarding Energy Efficiency Conservation
A-17	Letter dated October 21, 2011 – Commission Order G-177-11 with Reasons Decision establishing Interim Rates for the FortisBC Energy Utilities
A-18	Letter dated December 14, 2011 – Response to FEU letter dated December 12, 2011 Exhibit B-91
A-19	Letter dated December 21, 2011 – Response to BCOAPO request
A-20	Letter dated January 10, 2012 – Request Comments regarding Transcript correction
A-21	Letter and Order G-5-12 dated January 17, 2012 – Accepting FEU Transcript Correction
A2-1	Letter Dated June 2, 2011 – Commission Staff filing - Energy Law Journal – The efficient allocation of proceeds from a utility's sale of assets Volume 22, No. 2 2001
A2-2	Submitted at Oral Hearing October 3, 2011 – Commission Staff filing-POLICY PANEL -STAFF WITNESS AIDS
A2-2a	Submitted at Oral Hearing October 3, 2011 – Commission Staff filing-COLOURISED VERSIONS OF THREE GRAPHS IN EXHIBIT A2-2
A2-3	Submitted at Oral Hearing October 4, 2011 – Commission Staff filing - FINANCE PANEL STAFF WITNESS AIDS (PART 1)
A2-3a	Submitted at Oral Hearing October 4, 2011 – Commission Staff filing - TWO COLOURISED GRAPHS, HEADED BCUC STAFF WITNESS AID
A2-3b	Submitted at Oral Hearing October 4, 2011 – Commission Staff filing - EXTRACT FROM BCUC ORDER G-113-04
A2-4	Submitted at Oral Hearing October 6, 2011 – Commission Staff filing - DOCUMENT ENTITLED "2012/2013 FEU RRA HEARING, ENERGY SOLUTIONS PANEL-STAFF WITNESS AIDS"
A2-4a	Submitted at Oral Hearing October 6, 2011 – Commission Staff filing - COLOURIZED VERSIONS OF PIE CHART AND TWO GRAPHS CONTAINED IN EXHIBIT A2-4
~~A2-4b~~	No Exhibit A2-4b

EXHIBIT NO.	DESCRIPTION
A2-4c	Submitted at Oral Hearing October 7, 2011 – Commission Staff filing - 2010-2011 REVENUE REQUIREMENTS APPLICATION PAGE 373
A2-4d	Submitted at Oral Hearing October 7, 2011 – Commission Staff filing - TWO-PAGE DOCUMENT, "FORTIS ENERGY UTILITIES (COMBINED) OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW"
A2-5	Submitted at Oral Hearing October 11, 2011 – Commission Staff filing DOCUMENT HEADED "2012/2013 FEU RRA HEARING, OPERATIONS PANEL – STAFF WITNESS AIDS"
A2-5a	Submitted at Oral Hearing October 11, 2011 – Commission Staff filing EXTRACT HEADED "TERASEN GAS INC., 2010-2011 REVENUE REQUIREMENTS APPLICATION," PAGE 355
A2-5b	Submitted at Oral Hearing October 11, 2011 – Commission Staff filing - EXTRACT HEADED "TERASEN GAS INC., 2010-2011 REVENUE REQUIREMENTS APPLICATION," PAGE 507
A2-6	Submitted at Oral Hearing November 14, 2011 – Commission Staff filing - 2010 ENERGY EFFICIENCY AND CONSERVATION ANNUAL REPORT
A2-7	Submitted at Oral Hearing November 14, 2011 – Commission Staff filing - MEMPR INFORMATION BULLETIN 09-05
A2-8	Submitted at Oral Hearing November 14, 2011 – Commission Staff filing - DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS UTILITIES
A2-9	Submitted at Oral Hearing November 14, 2011 – Commission Staff filing - EB-2011-0295 - 2012 to 2014 Demand Side Management ("DSM") Plan

EXHIBIT NO.	**DESCRIPTION**
APPLICANT DOCUMENTS	
B-1	**FORTISBC ENERGY UTILITIES (FEU)** Letter dated May 4, 2011 - Application for 2012 and 2013 Revenue Requirements and Natural Gas Rates
B-1-1	**CONFIDENTIAL** Letter dated May 4, 2011 – FEU CONFIDENTIAL 2012 and 2013 Revenue Requirements and Natural Gas Rates Application
B-1-2	Letter dated May 16, 2011 – FEU Submitting Amendment to the Application
B-1-3	Letter dated September 28, 2011 - FEU Submitting Update of Tables in the Application based on the Evidentiary Update Exhibit B-21
B-1-4	Letter dated September 29, 2011 - FEU Submitting Additional Application Tables Update per Evidentiary Update Sept 12 Additional Pages
B-2	Letter dated May 18, 2011 – FEU Submitting Workshop Presentation Materials
B-3	Letter dated June 17, 2011 – FEU Submitting Application Working Tables and Live Spreadsheets
B-4	**CONFIDENTIAL** Letter dated June 17, 2011 – FEU CONFIDENTIAL Application EEC Financial Model Live Spreadsheets
B-5	Letter dated June 30, 2011 – FEU Responses to BC Hydro Information Request No. 1
B-6	Letter dated June 30, 2011 – FEU Responses to BCOAPO Information Request No. 1
B-7	Letter dated June 30, 2011 – FEU Responses to BCSEA Information Request No. 1
B-8	Letter dated June 30, 2011 – FEU Responses to CEC Information Request No. 1
B-9	Letter dated June 30, 2011 – FEU Responses to BCUC Information Request No. 1
B-9-1	Letter dated June 30, 2011 – FEU Attachments to the Responses to BCUC IR No. 1
B-10	**CONFIDENTIAL** Letter dated June 30, 2011 – FEU CONFIDENTIAL Responses to BCUC Information Request No. 1
B-10-1	**CONFIDENTIAL** Letter dated July 18, 2011 – FEU Errata to CONFIDENTIAL Responses to BCUC Information Request No. 1_1.189.2 and 1.201.1
B-11	Letter dated July 19, 2011 – FEU Submitting Evidentiary Update

EXHIBIT NO.	**DESCRIPTION**
B-12	Letter dated August 19, 2011 – FEU Response to BCOAPO Information Request No. 2
B-13	Letter dated August 19, 2011 – FEU Response to BCSEA Information Request No. 2
B-14	Letter dated August 19, 2011 – FEU Response to CEC Information Request No. 2
B-15	Letter dated August 19, 2011 – FEU Response to Corix Information Request No. 2
B-16	Letter dated August 19, 2011 – FEU Response to ESAC Information Request No. 2
B-17	Letter dated August 19, 2011 – FEU Response to BCUC Information Request No. 2
B-17-1	**CONFIDENTIAL** Letter dated August 19, 2011 – FEU CONFIDENTIAL Attachments to BCUC Information Request No. 2
B-17-2	Letter dated August 24, 2011 – FEU Submitting Attachment 97.1 to the Response to BCUC Information Request 2.97.1
B-17-3	Letter dated September 1, 2011 – FEU Submitting Response to BCUC Information Request 2.138.3
B-18	Letter dated August 30, 2011 – FEU Submitting EEC Financial Models Output
B-19	Letter dated August 30, 2011 – FEU Submitting Response to Variance Request G-129-11
B-20	Letter dated September 7, 2011 – FEU Submitting Reply Submissions to Intervener Comments
B-21	Letter dated September 12, 2011 – FEU Submitting Evidentiary Update
B-22	Letter dated September 14, 2011 – FEU Submitting Responses to BCUC Supplemental Information Request
B-23	Letter dated September 26, 2011 – FEU Submitting Witness Panels, Evidence and Opening Statement
B-24	Letter dated September 26, 2011 – FEU Submitting Application for Interim Rates effective January 1, 2012
B-25	Letter dated September 26, 2011 – FEU Submitting Rebuttal Evidence to the Direct Testimony of John Plunkett on Behalf of the BCSEA
B-26	Submitted at Oral Hearing October 4, 2011 – FEU RESPONSE TO UNDERTAKING NO. 1

Exhibit No.	**Description**
B-27	Submitted at Oral Hearing October 4, 2011 – FEU RESPONSE TO UNDERTAKING NO. 2
B-28	Submitted at Oral Hearing October 4, 2011 – FEU RESPONSE TO UNDERTAKING NO. 3
B-29	Submitted at Oral Hearing October 4, 2011 – FEU RESPONSE TO UNDERTAKING NO. 4
B-30	Submitted at Oral Hearing October 5, 2011 – EXCERPTS FROM THREE DOCUMENTS RE:RELEVANCY OF THE SOOKE CPCN
B-31	Submitted at Oral Hearing October 5, 2011 – FEU RESPONSE TO UNDERTAKING NO. 5
B-32	Submitted at Oral Hearing October 5, 2011 – FEU RESPONSE TO UNDERTAKING NO. 6
B-33	Submitted at Oral Hearing October 5, 2011 – FEU RESPONSE TO UNDERTAKING NO. 7
B-34	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 8
B-35	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 9
B-36	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 10
B-37	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 11
B-38	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 12
B-39	Submitted at Oral Hearing October 6, 2011 – FEU RESPONSE TO UNDERTAKING NO. 13
B-40	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 14
B-41	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 15

EXHIBIT NO.	DESCRIPTION
B-42	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 16
B-43	Submitted at Oral Hearing October 7, 2011 – FEU SUBMITTING Page from TGI 2010-2011 RRA-B-12 TGI MARKETING & BUSINESS DEVELOPMENT 2009
B-44	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 17
B-45	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 18
B-46	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 19
B-47	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 20
B-48	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 21
B-49	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 22
B-50	Submitted at Oral Hearing October 11, 2011 – Graph in response to BCUC Staff Witness Aid (Exhibit A2-5, Ref B-17, BCUC 2.74.1 Ops Centre Staffing)
B-51	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 23
B-52	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 24
B-53	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 25
B-54	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 26
B-55	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 27

EXHIBIT NO.	**DESCRIPTION**
B-56	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 28
B-57	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 29
B-58	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 30
B-59	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 31
B-60	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 32
B-61	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 33
B-62	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 34
B-63	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 35
B-64	Submitted at Oral Hearing October 11, 2011 – FEU RESPONSE TO UNDERTAKING NO. 36
B-65	Submitted at Oral Hearing October 7, 2011 – FEU RESPONSE TO UNDERTAKING NO. 37
B-66	Letter dated October 25, 2011 – FEU Submitting Interim Rates Fort Nelson Revised Financial Schedules
B-67	Letter dated November 7, 2011 - FEU Responses to BCUC Information Request No. 3
B-67-1	**CONFIDENTIAL** Letter dated November 7, 2011 - FEU CONFIDENTIAL Responses to BCUC Information Request No. 3
B-68	Letter dated November 7, 2011 - FEU Responses to BCOAPO Information Request No. 3
B-69	Letter dated November 7, 2011 - FEU Responses to BCSEA Information Request No. 3

EXHIBIT NO.	DESCRIPTION
B-70	Letter dated November 7, 2011 - FEU Responses to Corix Information Request No. 3
B-71	Submitted at Hearing November 14, 2011 – FEU RESPONSE TO UNDERTAKING NO. 38
B-72	Submitted at Hearing November 14, 2011 – FEU RESPONSE TO UNDERTAKING NO. 39
B-73	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 40
B-74	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 41
B-75	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 42
B-76	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 43
B-77	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 44
B-78	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 45
B-79	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 46
B-80	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 47
B-81	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 48
B-82	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 49
B-83	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 50
B-84	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 51

EXHIBIT NO.	DESCRIPTION
B-85	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 52
B-86	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 53
B-87	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 54
B-88	Letter Submitted November 29, 2011 - FEU RESPONSE TO UNDERTAKING NO. 55
B-89	Letter Submitted November 30, 2011 - FEU RESPONSE TO UNDERTAKING NO. 56
B-90	Letter Submitted November 30, 2011 - FEU RESPONSE TO UNDERTAKING NO. 57
B-91	Letter dated December 12, 2011 - FEU Submitting Response to BCOAPO regarding Demand-Side Measures Regulation Exhibit C1-8
B-92	Letter dated December 16, 2011 – FEU Submission regarding Demand-Side Measures Regulation
B-93	Letter dated December 20, 2011 – FEU Submission regarding BCOAPO extension Request
B-94	Letter dated January 6, 2012 – FEU Submission regarding correction to the transcript
B-95	Letter dated January 13, 2012 – FEU Reply Submission regarding correction to the transcript

EXHIBIT NO.	DESCRIPTION
INTERVENER DOCUMENTS	
C1-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION (BCOAPO) VIA EMAIL** Letter dated May 10, 2011 Via Email – Request for Intervener Status by Jim Quail and James Wightman
C1-2	Letter dated June 9, 2011 – BCOAPO Submitting Information Request No. 1
C1-3	Letter dated July 21, 2011 – BCOAPO Submitting Information Request No. 2
C1-4	Letter dated September 16, 2011 - BCOAPO Submitting update to contact information and Counsel
C1-5	Submitted at Oral Hearing October 4, 2011 – BCOAPO WITNESS AID FOR PANEL 2
C1-6	Submitted at Oral Hearing October 6, 2011 – BCOAPO WITNESS AID FOR PANEL 3
C1-7	Letter dated October 24, 2011 - BCOAPO Submitting Information Request No. 3
C1-8	Letter dated December 9, 2011 - BCOAPO Submitting comments regarding Demand-Side Measures Regulation
C2-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CEC) VIA EMAIL** Letter Dated May 10, 2011 Via Email – Request for Intervener Status by Christopher Weafer
C2-2	Letter dated June 9, 2011 – CEC Submitting Information Request No. 1
C2-3	Letter dated July 21, 2011 – CEC notice of late filing of Information Request No. 2
C2-4	Letter dated July 25, 2011 – CEC Submitting Information Request No. 2
C2-5	Submitted at Oral Hearing October 4, 2011 – CEC WITNESS AID FOR PANEL 2
C2-6	Submitted at Oral Hearing October 6, 2011 – CEC WITNESS AID FOR PANEL 3
C2-7	Submitted at Oral Hearing October 6, 2011 – EXCERPT FROM TGI - CNG/LNG SERVICE VEHICLES APPLICATION, EXHIBIT B-1
C2-8	Submitted at Oral Hearing October 6, 2011 – CEC WITNESS AID FOR PANEL 3 LABELED"CALCULATION OF CAPTURE RATIO 2001 TO 2013 FOR RESIDENTIAL NET ADDITIONS"
C3-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration dated May 11, 2011 - Request for Intervener Status by Janet Fraser

EXHIBIT NO.	**DESCRIPTION**
C3-2	Letter dated June 8, 2011 – BCH Submitting Information Request No. 1
C4-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB BRITISH COLUMBIA (BCSEA)** Letter dated May 11, 2011 – Request for Intervener Status by William J. Andrews and Thomas Hackney
C4-2	Letter dated June 9, 2011 – BCSEA Submitting Information Request No. 1
C4-3	Letter dated July 21, 2011 – BCSEA Submitting Information Request No. 2
C4-4	Letter dated August 23, 2011 – BCSEA Submitting direct written testimony of John Plunkett, Green Energy Economics Group
C4-5	Letter dated September 20, 2011 – BCSEA Submitting responses to BCUC Information Request No. 1
C4-6	Letter dated October 21, 2011 - BCSEA Submitting Information Request No. 3
C4-7	Submitted at Oral Hearing November 14, 2011 – THREE PAGE BCSEA WITNESS AID
C5-1	**ENERGY SERVICES ASSOCIATION OF CANADA (ESAC)** Letter dated May 16, 2011 – Request for Intervener Status by Karl Gustafson, Ronald Cliff and Peter Love
C5-2	Letter dated July 21, 2011 – ESAC Submitting Information Request No. 2
C5-3	Letter dated August 31, 2011 – ESAC Submitting comments regarding Variance Application
C5-4	Submitted at Oral Hearing November 14, 2011 – ESAC Submitting PAGES 394 AND 395, FORTIS RESPONSE TO BCUC IR NO. 1 DATED NOVEMBER 3, 2011
C5-5	Submitted at Oral Hearing November 14, 2011 – ESAC Submitting THREE-PAGE DOCUMENT, FIRST PAGE HEADED "TERASEN ENERGY SERVICES, ENERGY SUSTAINABILITY IS IN OUR NATURE"
C5-6	Letter dated January 12, 2012 – ESAC Response to Exhibit A-20 regarding FEU Transcript correction
C5-7	Letter dated January 20, 2012 – ESAC Submitting comments on the FEU's transcript correction
C6-1	**CORIX MULTI UTILITY SERVICES INC. (CORIX)** Letter dated May 31, 2011 – Request for Intervener Status by Ian Wigington and David Bursey

EXHIBIT NO.	**DESCRIPTION**
C6-2	Letter dated July 21, 2011 – Corix Submitting Information Request No. 2
C6-3	Letter dated September 1, 2011 – Corix Submitting comments regarding Variance Application
C6-4	Letter dated October 24, 2011 - Corix Submitting Information Request No. 3
C6-5	Letter dated January 12, 2012 – Corix Response to Exhibit A-20 regarding FEU Transcript correction
C6-6	Letter dated January 20, 2012 – Corix Submitting comments on the FEU's transcript correction
C7-1	**CLEAN ENERGY FUELS (CEF)** Letter dated September 14, 2011 – Request for Late Intervener Status by Brian Powers
C8-1	**LARGE INDUSTRIAL USERS GROUP (LIUG)** Letter dated September 14, 2011 Via Email – Request for Late Intervener Status by Jim Langley

INTERESTED PARTY DOCUMENTS

D-1	**ACCESS GAS SERVICES INC. (AGS)** Online registration dated June 1, 2011 – Request for Interested Party Status by Tom Dixon
D-2	**ACTIVE RENEWABLE (BC)** – Online Registration dated July 17, 2011 – Request for Interested Party Status by Bill Daly
D-3	**PEACE RIVER REGIONAL DISTRICT (PRRD)** – Online Registration dated January 20, 2012 – Request for Late Interested Party Status by Fred Banham

LETTERS OF COMMENT

E-1	**MINISTRY OF ENERGY AND MINES** – Via Email Letter of Comment dated October 3, 2011